2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT

P95 15% CAPACITY CREDIT BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,456	$4,494	$10	$75	$78	$81	$85	$88	$91	$124	$125	$128	$131
2 Congestion and Losses	($279)	($774)	($3)	($16)	($17)	($17)	($19)	($21)	($23)	($26)	($28)	($28)	($28)
3 Capacity Value	$70	$311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$350**	**$1,470**	**$4**	**$0**	**$2**	**$2**	**$6**	**$6**	**$10**	**$42**	**$44**	**$49**	**$42**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$135	$138	$143	$148	$150	$154	$156	$160	$166	$170	$175	$178	$185
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)
3 Capacity Value	$0	$0	$0	$0	$0	$1	$54	$55	($1)	$56	$55	($3)	($1)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($22)**	**($8)**	**$3**	**$11**	**$14**	**$21**	**$79**	**$86**	**$37**	**$100**	**$105**	**$53**	**$64**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$193	$198	$207	$212	$211	$213	$185
2 Congestion and Losses	($28)	($28)	($28)	($28)	($28)	($28)	($23)
3 Capacity Value	($0)	($1)	$50	$46	($3)	($2)	$4
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$74**	**$80**	**$142**	**$144**	**$95**	**$98**	**$86**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P95 15% CAPACITY CREDIT BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,273	$3,880	$10	$75	$78	$81	$84	$87	$90	$94	$97	$100	$104
2 Congestion and Losses	($233)	($628)	($3)	($16)	($17)	($17)	($18)	($19)	($20)	($21)	($22)	($22)	($22)
3 Capacity Value	$57	$274	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0.4)	($3.2)	($7.7)	($11.5)	($14.2)	($16.1)	($17.4)	($18.2)	($18.7)	($18.9)	($18.2)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$199**	**$964**	**$4**	**$0**	**$2**	**$1**	**$6**	**$8**	**$12**	**$16**	**$22**	**$27**	**$20**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$108	$112	$121	$126	$128	$133	$135	$134	$141	$142	$148	$153	$159
2 Congestion and Losses	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)	($22)
3 Capacity Value	$0	$0	($7)	($7)	($8)	($6)	$47	$55	($0)	$55	$52	($1)	$2
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($43)**	**($28)**	**($20)**	**($13)**	**($9)**	**($0)**	**$57**	**$65**	**$18**	**$77**	**$82**	**$36**	**$46**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$168	$173	$178	$183	$185	$188	$163
2 Congestion and Losses	($22)	($22)	($22)	($22)	($22)	($22)	($18)
3 Capacity Value	$3	$1	$47	$44	($3)	($2)	$4
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$58**	**$64**	**$115**	**$119**	**$75**	**$78**	**$69**

Benefits of Selected Wind Facilities (Low P95)

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P95 15% CAPACITY CREDIT LOW GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,275	$3,953	$9	$65	$67	$70	$73	$75	$77	$108	$108	$111	$114
2 Congestion and Losses	($241)	($671)	($2)	($14)	($14)	($15)	($17)	($18)	($20)	($22)	($24)	($24)	($24)
3 Capacity Value	$63	$313	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Total Net Customer Benefits/(Cost)	**$199**	**$1,035**	**$3**	**($7)**	**($6)**	**($8)**	**($4)**	**($4)**	**($1)**	**$29**	**$31**	**$35**	**$28**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$117	$119	$129	$133	$136	$140	$143	$140	$146	$149	$153	$157	$162
2 Congestion and Losses	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)	($24)
3 Capacity Value	$0	$0	($7)	($7)	($8)	($6)	$47	$55	($1)	$57	$56	($4)	($3)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($37)**	**($24)**	**($14)**	**($8)**	**($3)**	**$4**	**$63**	**$70**	**$20**	**$83**	**$89**	**$35**	**$43**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$169	$174	$180	$185	$189	$190	$166
2 Congestion and Losses	($24)	($24)	($24)	($24)	($24)	($24)	($20)
3 Capacity Value	($2)	($3)	$58	$57	$9	$9	$6
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$52**	**$58**	**$126**	**$132**	**$89**	**$90**	**$72**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
P95 15% CAPACITY CREDIT HIGH GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - No Tie Line
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,622	$5,002	$11	$83	$87	$91	$95	$99	$103	$137	$138	$142	$145
2 Congestion and Losses	($310)	($861)	($3)	($18)	($19)	($19)	($22)	($24)	($26)	($28)	($31)	($31)	($31)
3 Capacity Value	$68	$301	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0.4)	($3.2)	($7.7)	($11.5)	($14.2)	($16.1)	($17.4)	($18.2)	($18.7)	($18.9)	($18.2)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$482**	**$1,881**	**$4**	**$7**	**$9**	**$9**	**$14**	**$15**	**$19**	**$52**	**$54**	**$59**	**$53**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$150	$153	$159	$164	$167	$172	$175	$179	$185	$190	$197	$202	$210
2 Congestion and Losses	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)	($31)
3 Capacity Value	$0	$0	$0	$0	$0	$2	$51	$52	$1	$52	$48	$1	$6
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**($11)**	**$3**	**$16**	**$24**	**$29**	**$37**	**$91**	**$99**	**$56**	**$113**	**$118**	**$78**	**$92**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$218	$221	$228	$234	$232	$233	$201
2 Congestion and Losses	($31)	($31)	($31)	($31)	($31)	($31)	($26)
3 Capacity Value	$7	$4	$38	$35	($1)	($1)	$6
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	$0	$0	$0	$0	$0	$0	$0
8. Total Net Customer Benefits/(Cost)	**$103**	**$106**	**$148**	**$152**	**$115**	**$115**	**$100**

Benefits of Selected Wind Facilities (High P95)

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P50 15% CAPACITY CREDIT BASE GAS WITH CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - Tie Line In Service 2026

$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,684	$5,168	$12	$89	$92	$97	$101	$105	$105	$143	$144	$148	$151
2 Congestion and Losses	($113)	($149)	($3)	($26)	($27)	($28)	($31)	($34)	$0	$0	$0	$0	$0
3 Capacity Value	$70	$311	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0 4)	($3 6)	($8 9)	($13 4)	($16 7)	($19 1)	($21 1)	($22 4)	($23 3)	($24 1)	($24 3)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8. Total Net Customer Benefits/(Cost)	**$567**	**$2,136**	**$7**	**$16**	**$18**	**$17**	**$20**	**$20**	**$21**	**$60**	**$65**	**$70**	**$62**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$156	$159	$165	$171	$172	$177	$178	$182	$191	$193	$199	$204	$213
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	$0	$0	$0	$0	$0	$1	$54	$55	($1)	$56	$55	($3)	($1)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8 Total Net Customer Benefits/(Cost)	**($14)**	**$2**	**$18**	**$30**	**$35**	**$44**	**$100**	**$109**	**$63**	**$125**	**$132**	**$82**	**$94**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$221	$227	$234	$241	$242	$245	$213
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	($0)	($1)	$50	$46	($3)	($2)	$4
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8. Total Net Customer Benefits/(Cost)	**$105**	**$113**	**$172**	**$176**	**$129**	**$133**	**$114**

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P50 15% CAPACITY CREDIT BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - Tie Line In Service 2026
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,428	$4,359	$12	$88	$92	$96	$100	$104	$104	$108	$98	$101	$105
2 Congestion and Losses	($109)	($143)	($3)	($26)	($27)	($28)	($29)	($30)	$0	$0	$0	$0	$0
3 Capacity Value	$108	$368	$0	$0	$0	$0	$0	$0	$0	$0	$20	$20	$20
4 Production Tax Credits, Grossed Up	$630	$963	$15	$88	$91	$92	$95	$95	$98	$98	$102	$102	$87
5 Deferred Tax Asset Carrying Charges	($123)	($212)	($0 4)	($3 6)	($8 9)	($13 4)	($16 7)	($19 1)	($21 1)	($22 4)	($23 3)	($24 1)	($24 3)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8. Total Net Customer Benefits/(Cost)	**$354**	**$1,390**	**$7**	**$16**	**$18**	**$16**	**$21**	**$22**	**$20**	**$25**	**$39**	**$44**	**$36**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$110	$114	$133	$139	$141	$146	$148	$152	$161	$162	$169	$176	$182
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	$21	$21	($2)	($2)	($2)	($1)	$52	$53	($4)	$53	$51	($4)	($3)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($20)	($12)	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8 Total Net Customer Benefits/(Cost)	**($40)**	**($24)**	**($15)**	**($3)**	**$2**	**$11**	**$69**	**$76**	**$31**	**$91**	**$97**	**$52**	**$62**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$192	$199	$202	$208	$213	$216	$188
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	($4)	($2)	$45	$42	($5)	($4)	$3
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8. Total Net Customer Benefits/(Cost)	**$72**	**$83**	**$135**	**$140**	**$99**	**$102**	**$87**

Benefits of Selected Wind Facilities (Base No Carbon Gen Tie P50)

2019 Wind RFP - SWEPCO 810 MW SHARE OF PROJECT
NETWORK UPGRADES ONLY BRATTLE HIGHER CONGESTION CASE
P95 15% CAPACITY CREDIT BASE GAS NO CARBON CUSTOMER COSTS AND BENEFITS VS MARKET - Tie Line In Service 2026
$ in Millions (Nominal unless otherwise indicated)

Year	NPV	Total 31 Yr. Nominal	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1 Production Cost Savings Excluding Congestion/Losses	$1,233	$3,766	$10	$77	$80	$83	$87	$90	$90	$94	$83	$86	$89
2 Congestion and Losses	($94)	($124)	($3)	($22)	($23)	($24)	($25)	($26)	$0	$0	$0	$0	$0
3 Capacity Value	$108	$368	$0	$0	$0	$0	$0	$0	$0	$0	$20	$20	$20
4 Production Tax Credits, Grossed Up	$546	$834	$13	$76	$79	$79	$82	$82	$85	$85	$88	$88	$75
5 Deferred Tax Asset Carrying Charges	($96)	($163)	($0 4)	($3 2)	($7 7)	($11 5)	($14 2)	($16 1)	($17 4)	($18 2)	($18 7)	($18 9)	($18 2)
6 Wind Facility Revenue Requirement	($1,348)	($3,233)	($17)	($132)	($130)	($130)	($128)	($127)	($126)	($124)	($123)	($121)	($119)
7 Tie Line Revenue Requirement	($233)	($712)	$0	$0	$0	$0	$0	$0	($36)	($35)	($35)	($34)	($34)
8. Total Net Customer Benefits/(Cost)	**$116**	**$738**	**$4**	**($4)**	**($2)**	**($3)**	**$2**	**$3**	**($4)**	**$1**	**$15**	**$21**	**$15**

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Production Cost Savings Excluding Congestion/Losses	$93	$97	$115	$120	$122	$127	$128	$132	$140	$140	$146	$152	$158
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	$21	$21	($2)	($2)	($2)	($1)	$52	$53	($4)	$53	$51	($4)	($3)
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	($13)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($116)	($114)	($112)	($110)	($108)	($106)	($104)	($102)	($100)	($98)	($97)	($95)	($93)
7 Tie Line Revenue Requirement	($33)	($32)	($31)	($30)	($30)	($29)	($28)	($27)	($26)	($26)	($26)	($25)	($25)
8. Total Net Customer Benefits/(Cost)	**($49)**	**($34)**	**($30)**	**($22)**	**($17)**	**($8)**	**$48**	**$56**	**$9**	**$69**	**$74**	**$28**	**$38**

Year	2045	2046	2047	2048	2049	2050	2051
1 Production Cost Savings Excluding Congestion/Losses	$167	$172	$175	$180	$185	$187	$162
2 Congestion and Losses	$0	$0	$0	$0	$0	$0	$0
3 Capacity Value	($4)	($2)	$45	$42	($5)	($4)	$3
4 Production Tax Credits, Grossed Up	$0	$0	$0	$0	$0	$0	$0
5 Deferred Tax Asset Carrying Charges	$0	$0	$0	$0	$0	$0	$0
6 Wind Facility Revenue Requirement	($91)	($89)	($88)	($86)	($85)	($86)	($81)
7 Tie Line Revenue Requirement	($25)	($25)	($24)	($24)	($24)	($24)	($24)
8. Total Net Customer Benefits/(Cost)	**$47**	**$56**	**$108**	**$112**	**$71**	**$74**	**$61**

Benefits of Selected Wind Facilities (Base No Carbon Gen-Tie P95)

Natural Gas Price and Other Sensitivities

SWEPCO

Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P50 Capacity Factor Cases			
1	High Gas With CO2	$741	$526	$2,595
2	Base Gas With CO2	$588	$424	$2,120
3	Base Gas Without CO2	$415	$323	$1,540
4	Low Gas With CO2	$414	$298	$1,612
5	Low Gas Without CO2	$253	$214	$1,055

Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P95 Capacity Factor Cases			
1	High Gas With CO2	$482	$295	$1,881
2	Base Gas With CO2	$350	$206	$1,470
3	Base Gas Without CO2	$199	$119	$964
4	Low Gas With CO2	$199	$97	$1,035

	Higher Congestion With Tie Line In Service 2026			
Line	Amounts in Millions	31 Year NPV	PTC Period - First 11 years Nominal Total	Full 31 Year Nominal Total
	P50 Capacity Factor Cases			
1	Base Gas With CO2	$567	$374	$2,136
2	Base Gas Without CO2	$354	$264	$1,390
	P95 Capacity Factor Case			
3	Base Gas Without CO2	$116	$47	$738

PUC DOCKET NO. ________

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

JOHANNES P. PFEIFENBERGER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JPP-1	QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Johannes P. Pfeifenberger. I am a Principal at The Brattle Group and I am based in the company's Boston office. My business address is One Beacon Street, Suite 2600, Boston MA 02108.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Southwestern Electric Power Company (SWEPCO or the Company). SWEPCO and its sister company Public Service Company of Oklahoma (PSO) are operating companies of American Electric Power Company, Inc. (AEP) located in the Southwest Power Pool (SPP).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a M.A. in Economics and Finance from Brandeis University and a M.S. and B.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University of Technology, Vienna, Austria.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE AS THEY RELATE TO THIS DIRECT TESTIMONY.

A. I am an economist with a background in power engineering and over 25 years of work experience in the areas of regulated industries, energy policy, and finance. I am the author and co-author of numerous articles, reports, and presentations on subject areas related to regional power markets, the economic benefits of transmission investment, and renewable generation. For example, I have worked with SPP and its Regional State Committee (RSC) on a number of topics such as supporting SPP with the market simulations and quantification of transmission-related benefits for the Regional Cost

Allocation Reviews (RCAR) and working with the RSC to develop a framework for the planning and cost allocation of transmission projects that span regional market seams.

I have previously filed testimony addressing regional power markets, transmission, and renewable generation before a number of regulatory commissions, including in Oklahoma, Arkansas, Texas, Louisiana, Mississippi, Wisconsin, Illinois, Arizona, Maine, Alberta, and at the Federal Energy Regulatory Commission (FERC). For example, I have filed before FERC testimony on behalf of RITELine Transmission Development, LLC in Docket No. ER11-4049 regarding the congestion reduction and related economic and renewable integration benefits associated with the RITELine transmission project spanning from western Illinois to the Indiana-Ohio border within the ComEd and AEP zones of PJM Interconnection, L.L.C; and on behalf of the Atlantic Wind Connection Companies in Docket No. EL11-13 regarding the renewable integration, reliability, operational, congestion relief, and other benefits of the Atlantic Wind Connection Project, a proposed offshore high-voltage transmission backbone along the Mid-Atlantic coast to interconnect up to 6,000 MW of offshore wind generation with the PJM wholesale market. EXHIBIT JPP-1 to my testimony contains a more complete description of my qualifications and expert witness experience.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Together with PSO, SWEPCO has contracted to purchase three wind generation facilities (Selected Wind Facilities) that are the subject of this application. Subject to regulatory approvals and satisfaction of other conditions, SWEPCO will purchase a 54.5% share of the facilities and PSO will purchase the remaining 45.5% share. In the context of this selection, my testimony has four purposes.

First, I discuss the PROMOD® tool, and the SPP-developed Reference Case as utilized in the Company's bid evaluation and benefits analysis for the wind facilities proposed in response to its Request for Proposals (RFP).

Second, I explain SPP market congestion and losses, and why they are important to the value of a wind generation facility. I then provide an overview of congestion costs that have been experienced by wind plants in the SPP system and discuss the inherent uncertainty in estimating future congestion costs across time and locations.

Third, I testify to the reasonableness of the Company's RFP bid-evaluation process employed in choosing the Selected Wind Facilities. In reviewing the bid-evaluation process, I assess the reasonableness of the Company's assumptions, analyses, and approach employed to choose the Selected Wind Facilities, considering the costs of the bids, the locations of the wind farms, exposure to future system congestion and deliverability limitations, and the feasibility of deploying potential congestion risk mitigation options in the event that high levels of congestion materialize in the future.

Fourth, I review the assumptions, analyses, and approach employed by the Company to determine the customer benefits of the Selected Wind Facilities and then evaluate the reasonableness of the estimated benefits. My review specifically focuses on the reasonableness of the overall benefits evaluation methodology and the congestion and loss estimates for the Selected Wind Facilities as applied in the Company's customer benefit analysis.

III. OVERVIEW OF PROMOD AND THE SPP-DEVELOPED REFERENCE CASE

Q. WHAT DATA AND TOOL HAS THE COMPANY USED TO ESTIMATE SPP CONGESTION AND LOSS-RELATED COSTS FOR THE RFP BID EVALUATION AND FOR THE CUSTOMER BENEFITS ANALYSIS ASSOCIATED WITH THE SELECTED WIND FACILITIES?

A. The Company has relied on the PROMOD Reference Case that SPP developed through its currently, ongoing stakeholder-based 2019 Integrated Transmission Plan (ITP) process. With minor modifications to account for the proposed and selected wind facilities and upgrades to the SPP-identified transmission needs, the Company has relied on these SPP PROMOD cases for both the RFP bid evaluation analysis and for the customer benefits analysis, particularly for estimating congestion and loss-related costs in SPP.

I will discuss both the RFP bid evaluation and customer benefit analyses in this direct testimony, including a discussion of the key input assumptions for each. Witness Sheilendranath explains the specifics of how the estimates of potential future congestion and losses were developed through PROMOD simulations for both the RFP bid-evaluation and the customer benefits analysis of the Selected Wind Facilities. He also discusses how PROMOD congestion and the Company's fundamentals forecasts were combined for the customer benefits analysis to develop the necessary estimates for wholesale energy market prices for the Company's load zone and generation locations.

Q. PLEASE EXPLAIN WHAT THE PROMOD MODEL IS, HOW IT GENERALLY WORKS, AND HOW IT CALCULATES CONGESTION AND LOSS COSTS.

A. PROMOD is a widely-used and universally-accepted market and production cost simulation tool, primarily employed for forward-looking locational market simulations. PROMOD simulations are premised on a competitive wholesale electricity market. SPP uses PROMOD to simulate, for the assumed market conditions, the chronological hourly dispatch of generation needed to meet load in the entire SPP footprint and neighboring markets, subject to transmission constraints. Among the main simulation outputs are the locational market prices (LMP) for SPP load zones and individual generation resources. PROMOD outputs also include the hourly marginal congestion cost and marginal loss charge components of the LMP for each pricing node. These marginal congestion cost and marginal loss charge components are essential for computing congestion and loss-related costs associated with the delivery of power from generation facilities, including the wind generators being evaluated by the Company, to the AEP West load zone.

The PROMOD simulations, like those of similar other nodal market simulations, make certain simplified assumptions about market conditions that tend to yield conservatively low market price fluctuations and congestion levels. For example, PROMOD simulations generally use long-term projections of fuel prices (which do not have as much daily and monthly volatility as actual fuel prices), weather-normalized loads (which do not include occasional heat waves or unusual cold weather), and a fully intact transmission system (*i.e.*, no temporary transmission outages). Thus, the simulations do not capture the actual daily or monthly fluctuations in these variables, nor the added stresses associated with the encountered more challenging system conditions.

The simulations are based on perfect foresight of daily real-time conditions—which approximates day-ahead power markets but understates real-time market uncertainties, including variances in wind generation output and therefore the likely generation curtailment driven by the uncertainty of real-time market conditions and temporary transmission outages. Despite these simplifying assumptions and the associated impact, the simulation results are the best available projection of locational market conditions that are used for long-term transmission planning and congestion analyses.

Q. DOES SPP, THE MARKET WHERE PSO AND SWEPCO ARE LOCATED, USE PROMOD TO PROJECT CONGESTION AND LOSSES IN ITS REGIONAL FOOTPRINT?

A. Yes. PROMOD is SPP's main simulation tool for analyzing congestion and losses, including for analyzing how proposed new generation or transmission facilities affect locational market prices and costs within its market region. SPP uses PROMOD for both its ITP efforts as well as its periodic Regional Cost Allocation Reviews.

Q. PLEASE DESCRIBE THE PROMOD DATASET, AS DEVELOPED BY SPP AND ITS STAKEHOLDERS, WHICH THE COMPANY USED FOR THE BID EVALUATION AND CUSTOMER BENEFITS ANALYSES.

A. The PROMOD models developed for SPP's currently-ongoing 2019 ITP10 stakeholder process reflect the most current information regarding expected future system conditions. Because the data-intensive region-wide and locational simulations make it computationally challenging and time consuming to analyze more than a few years, SPP develops PROMOD cases for only select future years—including 2024 and 2029 for the currently-ongoing 2019 ITP effort.

The Company relied on the PROMOD "Reference Case (Future 1)" that SPP staff and stakeholders developed for the 2019 ITP.[1] As SPP notes, the objective of the 2019 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. The PROMOD models developed for this ITP effort include all SPP-planned and -approved transmission projects as well as planned and/or needed future generating resources, including wind resources at levels and locations that SPP and its stakeholders have deemed feasible for development by 2024 and 2029.

Q. ARE THE SPP REFERENCE CASE ASSUMPTIONS A REASONABLE STARTING POINT FOR THE COMPANY'S EVALUATION OF CONGESTION AND LOSSES OF WIND FACILITIES?

A. Yes, relying on the SPP Reference Case is reasonable for a number of reasons. First, the assumptions were developed by SPP staff and stakeholders independently of the Company's effort in this case. The SPP Reference Case represents a "current trends" case, which includes SPP and its stakeholders' general expectations about the future state of the market and does not include the more aspirational assumptions of SPP's "Emerging Technologies" Case. Second, the main assumptions that will affect the overall levels of wholesale power prices and congestion costs for the purpose of the

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[1] See SPP Engineering, *2019 Integrated Transmission Planning Assessment Scope*, Published on 10/16/2018, posted at: https://www.spp.org/documents/60005/2019%20itp%20scope.pdf

SPP also developed an "Emerging Technologies Future (Future 2)," which explores assumptions that include higher amounts of electric vehicles, distributed generation, demand response, energy efficiency, and higher wind and solar penetration based on an assumption of reduced technology costs.

Company's bid evaluation are reasonable within the range of both independent industry reference points and the Company's own market fundamentals forecasts.

Q. PLEASE SUMMARIZE THE SPP REFERENCE CASE ASSUMPTIONS.

A. The SPP Reference Case reflects a continuation of current industry trends and environmental regulations. This case assumes that coal and gas-fired generators over the age of 60 will be retired. Gas and coal prices are based on long-term industry forecasts. Specifically, the natural gas prices used in the SPP PROMOD simulations are based on ABB-developed forecasts, averaging $4.62/MMBtu in 2024 and $5.44/MMBtu in 2029 for Oklahoma. The 2024 and 2029 transmission topology reflects all transmission facilities that are included in the SPP Transmission Expansion Plan (STEP) including those that have already been approved for construction.[2] And, finally, the SPP Reference Case solar and wind additions exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations. Specifically, SPP includes in its PROMOD simulations a total of 24,200 MW of installed wind generation for 2024 and 24,600 MW by 2029. Solar generation has been assumed to grow from approximately 250 MW today to 3,000 MW in 2024 and 5,000 MW in 2029. I further discuss these SPP assumptions in my review of the Company's RFP bid evaluation and customer benefit analysis below.

IV. CONGESTION IN SPP

Q. WHAT ARE THE MAIN DRIVERS OF CONGESTION AND LOSS-RELATED COSTS IN THE SPP REGION?

[2] SPP's methodology for developing the transmission topology for its PROMOD cases is specified in its October 17, 2018 ITP Manual, Sections 2.1.4 (for reliability studies) and Section 2.2.1.6 (for economic studies). Available at: https://www.spp.org/Documents/22887/ITP%20Manual%20version%202.3.docx

A. Congestion and loss-related costs in SPP are driven by two major factors. First, congestion in SPP is driven to a large extent by the amount of interconnected wind generation relative to the transmission system's transfer capability, which determines the frequency and quantity of congestion on the SPP system. Second, the cost of transmission congestion and system losses will depend on the level of wholesale power prices and the underlying generation costs, which determine the $/MWh cost of supplying lost energy and managing congestion through generation redispatch. All else equal, the cost of congestion and losses would be greater as more wind generation facilities compete for limited transmission capability. Similarly, those costs increase when it is more costly to redispatch generating plants to manage power flows, including from constrained wind generation, to not exceed the capability of the transmission system. Conversely, congestion will decline as SPP facilitates the upgrade of transmission constraints and addresses other transmission needs.

Q. PLEASE EXPLAIN THE INHERENT UNCERTAINTY IN FORECASTING THE MAGNITUDE OF CONGESTION COSTS.

A. The level of congestion in the SPP footprint is difficult to forecast as it varies greatly both (1) over time and (2) across locations.

Often, the SPP transmission planning solutions have not been able to mitigate congestion costs in a timely fashion because the necessary transmission facilities can take 5–10 years to plan within the SPP transmission planning process and be built. Further, there are significant uncertainties around future generation resource mix in SPP. For example, there is a possibility that more wind generation could be built in the SPP footprint than projected due to the potential for future carbon charges or other environmental regulations of fossil resources, customers' shifting preferences for clean energy resources, continued declines in renewable generation costs, future increases in natural gas prices, and the retirement of older and inefficient generators. These uncertainties can affect future congestion in uncertain ways. In the absence of timely transmission upgrades, greater than expected additions of wind generation pose the risk that future increases in congestion costs could be significantly higher than currently projected. But it is also possible that SPP transmission upgrades will reduce congestion costs below projected levels.

Table 1 below illustrates this uncertainty for congestion between existing wind generation facilities in Oklahoma and the AEP West load zone by summarizing actual historical real-time market outcomes for 2014 through (year to date) 2019. Table 1 shows the simple historical averages of annual congestion charges between individual existing Oklahoma wind plants and the AEP West load zone. The historical annual congestion charges have ranged from a low of less than $1/MWh in 2014 and 2015 to approximately $8/MWh in 2017, before dropping to around $5/MWh in 2018 and $5.87/MWh (year to date) 2019—reflecting the congestion-reducing effect of SPP transmission additions that came online in recent years. Because the hourly wind generation data is not publicly available for SPP wind facilities, the numbers presents the simple averages of the congestion costs over all hours of the respective years. Although the simple averages will understate the actual annual congestion costs faced by the owners of these wind facilities, because hours with higher wind generation will tend to be correlated with higher congestion charges, these averages nevertheless document congestion trends over time and allow for a comparison of historical and simulated future congestion costs.

Table 1: Historical Wind-to-AEP West Congestion
For Oklahoma Wind Facilities
($/MWh, simple all-hours annual average)

	Capacity (MW)	2014	2015	2016	2017	2018	2019
Arbuckle Mountain Wind Project	100	-	-$0.30	-$0.92	-$0.06	$3.21	$1.74
Balko Wind Project	300	-	$5.12	$9.68	$13.86	$6.01	$6.55
Big Smile Wind Farm	132	$3.75	-$0.38	$2.24	$6.46	$5.45	$5.46
Blue Canyon	423	-$0.89	-$0.75	-$0.17	$4.44	$5.04	$4.35
Bluestem Wind Project	198	-	-	$15.63	$14.51	$5.97	$6.59
Canadian Hills Wind Project	299	-$0.87	-$0.40	$2.29	$5.12	$4.96	$6.80
Centennial Wind Farm	120	$9.48	$10.38	$17.69	$22.95	$6.28	$6.59
Chisolm View Wind Project I	235	$0.55	-$0.26	$1.80	$10.57	$6.65	$8.52
Crossroads Wind Project	227	$1.46	-$0.89	$0.24	$0.65	-$0.56	-$0.31
Drift Sand Wind Farm	108	-	-	-$1.12	$1.65	$2.78	$1.71
Elk City Wind	200	$3.75	-$0.38	$2.24	$6.46	$5.45	$5.46
Flat Ridge II	470	$1.69	$0.90	$2.70	$10.23	$6.30	$8.19
Goodwell Wind Project	200	-	$4.36	$8.72	$13.58	$6.07	$6.16
Grant Plains	147	-	-	$1.32	$9.87	$6.52	$8.45
Grant Wind Farm	152	-	$0.98	$1.76	$9.90	$6.53	$8.44
Great Western Wind Project	225	-	-	$17.59	$15.51	$5.97	$6.76
High Majestic Wind	159	$9.32	$4.81	$13.73	$14.56	$8.21	$6.06
Kay County Wind Project	299	-	$1.00	$2.09	$5.19	$5.09	$7.86
Kingfisher Wind Farm	298	-	-$0.58	$2.29	$5.12	$4.96	$6.80
Mammoth Plains Wind Energy	199	$2.10	$6.07	$12.25	$16.01	$5.99	$6.98
Minco Wind	199	-$0.89	-$0.36	$1.88	$4.67	$4.83	$6.01
Oklahoma (Sooner) Wind Energy Center	102	-$11.08	-$18.52	-$19.95	-$12.76	$3.41	$5.41
Origin Wind Energy Project	150	-$0.70	-$0.21	-$0.86	-$0.12	$2.53	$1.13
Osage Wind Farm	150	-$1.57	-$0.42	-$0.08	$0.92	-$0.19	$1.42
OU Spirit/CPV Keenan II	253	$8.29	$8.30	$14.60	$19.61	$6.06	$6.64
Persimmon Wind Farm	199	-	-	-	-	$6.28	$6.76
Red Dirt Wind Farm	300	-	-	-	$16.43	$5.63	$7.09
Red Hills Farm	123	-$0.81	-$3.68	-$2.43	$0.11	$3.58	$4.47
Rock Falls Wind Farm	155	-	-	-	-	$6.37	$9.85
Rocky Ridge Wind Project	149	$0.19	-$0.89	$0.21	$3.14	$3.01	$3.24
Rush Springs Wind Farm	250	-$0.97	-$0.58	-$0.85	$0.94	$2.42	$1.24
Seiling Wind I	199	$2.10	$6.06	$12.25	$16.03	$5.99	$6.98
Sleeping Bear	95	-$8.32	-$15.39	-$15.49	-$11.21	$3.73	$5.53
Taloga Wind Plant	130	-$1.09	-$3.95	$6.24	$10.91	$5.26	$5.12
Thunder Ranch Wind Farm	298	-	-	-	$2.68	$5.18	$7.21
Weatherford Wind Energy Center	147	-$0.39	-$1.54	-$4.44	-$1.09	$3.85	$4.08
MW-Weighted Avg		***$0.97***	***$0.64***	***$3.95***	***$7.80***	***$5.02***	***$5.87***

Source: Calculated from Real-Time congestion compiled by ABB Velocity Suite. Averages for 2019 are through May 9, 2019

Table 1 also shows that the differences across wind locations are just as significant as the overall year-to-year variances. The variances across locations are particularly pronounced in years with high overall congestion levels. For example, when average overall congestion levels were the highest at $7.80/MWh in 2017, the average annual congestion charges at the individual wind facilities ranged from *negative* $12.76/MWh (a credit) to *positive* $22.95/MWh (a cost). In contrast, after important SPP transmission upgrades came online and overall annual congestion dropped to $5.02/MWh in 2018, congestion charges for individual wind facilities ranged from a low of negative $0.56/MWh to a high of only $8.21/MWh.

Q. DO THE IMPACTS OF CONGESTION AND LOSSES ON WIND FACILITIES WITHIN THE SPP FOOTPRINT SIMILARLY AFFECT THE WHOLESALE POWER PRICES FOR THE COMPANY'S LOAD ZONE AND CONVENTIONAL GENERATION FACILITIES?

A. Yes, to some extent. Because the Company's load zone and conventional generation facilities are primarily located in the eastern portion of the SPP footprint, congestion and losses within SPP also affects the wholesale power prices paid by the Company to serve its load. Because of the prevailing west-to-east power flows in the SPP region, which cause congestion and losses along the way, the wholesale prices close to the Company's load tend to be higher than the average prices in SPP. The magnitude of these impacts is discussed further in my review of the Company's customer benefit analysis below.

V. REASONABLENESS OF THE COMPANY'S BID SELECTION

Q. PLEASE SUMMARIZE THE BID EVALUATION PROCESS THAT THE COMPANY USED TO CHOOSE THE SELECTED WIND FACILITIES.

A. As explained in detail by Company witness Godfrey, PSO and SWEPCO selected three wind facilities with 1,485 MW of total nameplate capacity from the proposals received. They arrived at this selection by: (a) applying the bid eligibility and threshold criteria (as specified in Section 9.1 of the RFP); and then (b) performing a detailed analysis of the proposed wind projects and their associated congestion costs and risks (Section 9.2.1 of the RFP with 90% weight); plus (c) an additional consideration of non-price factors (Section 9.2.2 of the RFP with 10% weight).

My review focuses on the economic portions of the evaluation process. In that regard, in performing the bid evaluation process, the Company:

1. Clustered the proposed wind facilities based on the similarity of the expected impact from their power flow (distribution factor or DFAX) on the transmission system;
2. Evaluated the deliverability of the wind facilities to the AEP West load zone by calculating the First Contingency Incremental Transfer Capability (FCITC) between each cluster of proposed wind facilities and the AEP West load zone;
3. Performed PROMOD market simulations to estimate congestion and loss costs associated with each of the wind project bids to estimate the likely delivery costs of the project's energy to Company loads;
4. Estimated the costs of mitigating congestion to account for the risk of incurring unexpectedly high congestion costs in the future, using the estimated cost of a generation-tie line as a proxy for its future congestion risk mitigation options; and
5. Calculated a Levelized Adjusted Cost of Energy (LACOE) as the sum of each bid's Levelized Cost of Energy (LCOE) plus (a) the bid's estimated congestion and loss cost (with 50% weight) and (b) the cost of mitigating congestion (with 50% weight).[3]

Q. DID THE COMPANY'S EVALUATION PROCESS RESULT IN REASONABLE SELECTION OF WIND FACILITIES FOR THE COMPANY TO PROCURE?

[3] In accordance with Section 9.2.1.2 the Company calculated as a preliminary metric of customer benefits the Levelized Net Revenue Requirement by taking the difference between (a) the levelized expected SPP Load Revenues for the Proposal's energy in the SPP market and (b) the LACOE for each Proposal. However, because the SPP load revenues of wind *delivered* to the AEP West load zone are essentially identical for all wind delivered to the AEP load zone, variations in this metric are a function of the LACOE. As a consequence, the LACOE was used directly for the "economic analysis" portion of project selection under Section 9.3 of the RFP.

A. Yes. The Company selected the most cost-effective wind projects that met the qualification thresholds, while considering the risks of future system constraints, congestion costs, and the cost of available options to mitigate the risks of incurring unexpectedly high congestion costs in the future.

Q. DID THE COMPANY USE THRESHOLD CRITERIA SPECIFIED IN SECTION 9.1 OF THE RFP TO EXCLUDE CERTAIN PROPOSED WIND FACILITIES FROM FURTHER EVALUATION USING THE ECONOMIC CRITERIA SPECIFIED IN SECTION 9.2?

A. Yes, as explained in the testimony of Company witness Godfrey, the Company received 19 proposals for individual wind projects with a total of 35 different configurations, totaling approximately 5,896 MW. Of these projects and configurations, eight proposals and 16 configurations did not meet the RFP-specified threshold criteria. Four of these eight proposals that did not meet the Section 9.1 threshold criteria (consisting of five configurations) were located in clusters that did not meet the FCITC deliverability criteria under Section 9.1.12 of the RFP. Company witness Ali discusses the deliverability assessment under Section 9.1.

Q. WAS IT REASONABLE THAT THE COMPANY "CLUSTERED" THE PROPOSED WIND FACILITIES IN ITS DELIVERABILITY ASSESSMENT?

A. Yes. Starting out by clustering wind farms based on their power flow impacts on the transmission system is an objective, reasonable approach to grouping wind projects such that their combined deliverability to load can be evaluated. The clusters are also necessary for the development of congestion mitigation options to address potential future congestion costs that might be significantly greater than those estimated. For all clusters that passed the cluster-based deliverability test under Section 9.1.12 of the RFP, the Company then analyzed both (1) congestion and loss costs associated with delivering each bid-in wind farm from each cluster to AEP West load zone; and (2) the cost of transmission solutions that might be available to mitigate these congestion costs should they rise to unexpectedly high levels. The estimated congestion costs are based on the Company's PROMOD market simulations using SPP's 2019 ITP PROMOD Reference Case model, with only slight modification as discussed below.

Q. PLEASE EXPLAIN WHY IT WAS REASONABLE TO INCLUDE THE FCITC DELIVERABILITY CRITERIA AS A THRESHOLD CRITERIA.

A. Assessing limitations in deliverability for clusters is a useful threshold criteria as it provides a good indication of the transmission capacity "head room" that exists on the SPP system for developing additional wind at these locations, considering that most of these projects will compete with other wind projects for available transmission capability. As explained by Company witness Ali, the deliverability assessment from the wind farms in each cluster to the Company's load zone is based on studying the FCITC, using standard industry methodology and the power flow models developed by SPP for its Definitive Interconnection System Impact Study (DISIS) that evaluates generation interconnection requests received during the DISIS Cluster Window. Specifically, the Company used the models developed for SPP's evaluation of Energy Resource Interconnection Service (ERIS) Requests, which ensures that transmission network upgrades identified by SPP to connect ERIS are considered in SPP's planning process.

The FCITC thus measures the robustness of the transmission system between wind locations and the AEP West load zone and quantifies the amount of transmission capability headroom that is available to accommodate the additional generation. Less available headroom means greater risks of encountering unexpectedly high congestion costs or wind generation curtailments, which could occur due to unexpected market fundamentals, transmission outages, or the interconnection of additional wind facilities in that location. The FCITC metric thus supplements the congestion cost estimates obtained through the PROMOD simulations by: (1) indicating how quickly congestion may increase beyond the congestion levels simulated in PROMOD due to the lack of transmission capability to accommodate additional wind facilities that may interconnect in the future; and (2) providing an indication of wind curtailment risks—a factor that can substantially increase the net cost of wind facilities but that is not captured adequately in PROMOD simulations due to the fact that these simulations do not consider temporary transmission outages or real-time market uncertainties, the main sources of wind curtailments. The FCITC headroom additionally indicates the likelihood of being able to obtain congestion hedges from SPP in the future for those locations (as more transfer capability will increase that likelihood).

There is some overlap between the FCITC as a threshold measure for analyzing congestion risk and the estimates of congestion costs and congestion risk mitigation costs that the Company has applied to evaluate qualifying bidders under Section 9.2.1 of the RFP. However, as shown below, even without applying FCITC as a Section 9.1 threshold criteria, the Section 9.2.1 economic cost and risk analysis would have ranked poorly those proposed projects eliminated via the FCITC metric compared to other remaining projects because congestion risk mitigation would be very expensive at these locations.

Q. HOW DID THE COMPANY EVALUATE POTENTIAL CONGESTION COSTS AND LOSSES FOR THE RFP BIDS THAT PASSED THE THRESHOLD CRITERIA?

A. As stated previously, the Company used SPP's PROMOD Reference Case for 2024 and 2029 as the starting point for the economic analysis of qualifying RFP bids. Through these nodal market simulations, the Company estimated the potential congestion costs and losses for each of the project bids.

Q. DID THE COMPANY UPDATE THE SPP REFERENCE CASE ASSUMPTIONS FOR THE PURPOSE OF THE RFP BID EVALUATION?

A. Yes, but only as required to add the RFP bid projects that were evaluated by the Company. As the first update, the Company added the wind facilities associated with individual RFP bids if those wind generation facilities were not already included in the SPP PROMOD Case. This involved the addition of approximately 4,400 MW of wind generation facilities submitted in the RFP that were not sufficiently advanced to be included by SPP when it developed its PROMOD case. Second, the Company relieved transmission constraints associated with the transmission upgrades that SPP identified in the DISIS and require through its generation interconnection process for the individual wind generation facilities bid into the Company's RFP.

Q. ARE THE ASSUMPTIONS IN THE SPP PROMOD CASE THAT THE COMPANY USED TO EVALUATE THE RFP BIDS REASONABLE?

A. Yes, they are. Focusing first on natural gas prices in the SPP Reference Case, I find that they are reasonable for the purpose of the Company's bid evaluation. The natural gas prices, along with other commodity price assumptions, are reviewed and approved by SPP stakeholders for inclusion in the ITP. While these ABB-developed natural gas price forecasts are higher than some other industry forecasts, they are well within the range of industry and current Company forecasts as shown further in Company witness Bletzacker's testimony. In addition, the absolute level of gas prices and associated wholesale power prices has a minimal impact on bid selection, which is driven more by the *relative* congestion costs across the wind generation proposals received in the response to the Company's RFP.[4]

Q. IS IT REASONABLE TO ADD THE WIND GENERATION FROM THE RFP BIDS?

A. Yes. With respect to the wind generation assumptions, SPP's Reference Case includes total wind generation capacity of 24,200 MW by 2024 and 24,600 MW by 2029 as noted earlier. With the addition of 4,400 MW of RFP bids that were not included in SPP's Reference Case, the PROMOD case used for bid evaluation includes a total of 29,000 MW of wind generation in the SPP footprint—an increase of 7,600 MW from the approximately 21,400 MW of wind generation installed today.[5] Coincidentally, this exactly matches the 7,600 MW of proposed SPP wind facilities that are "on schedule" in SPP's generation interconnection queue with a fully executed interconnection agreement and an SPP forecast of 28,000 MW to 33,000 MW of installed wind capacity by 2025.[6] While not all of the forecast wind facilities may actually be developed, ABB reports in

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[4] While bid evaluation is driven more by *relative* congestion costs, the *absolute* level of gas prices and associated wholesale power prices and congestion costs is more important for analyzing customer benefits associated with the Selected Wind Facilities. The Company consequently has evaluated customer benefits for a range of different natural gas price, wholesale power price, and congestion levels as discussed further in the Customer Impact Analysis Section of my testimony.

[5] See page 3 of https://www.spp.org/documents/59992/spp_mmu_qsom_winter_2019.pdf. Note that some of these wind resources may be considered in-service, but not yet in commercial operation. In this situation, the capacity will be counted but the resource may not be providing any generation to the market.

[6] See slide 123 of https://www.spp.org/documents/31587/intro%20to%20spp.pdf.

its Velocity Suite database that a total of 3,900 MW of these new wind facilities are already under construction or permitted.

Although the level of wind generation that will be installed over the next decade is uncertain—which leads to congestion risk and the need to evaluate mitigation options—the levels of wind generation additions included in the Company's SPP PROMOD simulations are reasonable.

Q. ARE THE TRANSMISSION ADJUSTMENTS TO THE SPP REFERENCE CASE REASONABLE FOR THE PURPOSE OF THE COMPANY'S BID-SELECTION PROCESS?

A. Yes. The Company has assumed that the SPP-required transmission upgrades to facilitate individual wind resources interconnection would be built. By relieving the constraints on transmission facilities for which SPP has identified upgrades as part of the wind plants' generation interconnection process, the simulations can ensure that the congestion-reducing impacts of the mandated transmission upgrades are reflected in the congestion results.[7]

Q. FOR THE PURPOSE OF ITS BID EVALUATION PROCESS, HAS THE COMPANY REFLECTED IN ITS MARKET SIMULATIONS ANY ADDITIONAL

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[7] Note that, to be able to simulate congestion realistically, the Company also had to analyze which new transmission constraints will likely be caused by adding new wind generation facilities to the simulations—and adding those new constraints to the list of monitored constraints in the PROMOD case that have been specified by SPP. This adjustment ensures that the Company's simulations can actually enforce the transmission capability limits associated with the constraints caused by the new wind generation additions. This "constraint identification" step is necessary because PROMOD cannot monitor power flows and enforce limitations for every single transmission facility in the footprint. Rather, to make the simulations computationally feasible, PROMOD monitors power flows and enforces limits only for a pre-specified set of transmission constraints.

TRANSMISSION UPGRADES THAT SPP MAY APPROVE FOR CONSTRUCTION AT SOME POINT IN THE FUTURE?

A. No. For the purpose of the RFP bid evaluation, and with only one exception,[8] the Company has not reflected in its PROMOD simulations other transmission upgrades that SPP may approve for construction aside from those already approved by SPP or identified by SPP as necessary to interconnect the wind facility bids in the RFP. While not modeling possible future SPP transmission upgrades may result in higher congestion costs than ultimately may be realized, doing so in this PROMOD "Bid Evaluation Case" is reasonable for the purpose of: (1) evaluating the various wind generation bids *relative to each other*; and (2) identifying the most attractive bids when including considerations for their potential congestion cost and risk exposure. As I explain further below, after the Selected Wind Facilities were chosen, the Company further refined the SPP PROMOD case to reflect its selection of wind facilities and likely future SPP transmission upgrades for the purpose of the customer benefit analysis.

Q. WHAT ARE THE PROMOD CONGESTION AND LOSS ESTIMATES USED FOR THE BID EVALUATION OF THE WIND FACILITIES PROPOSED IN THE RFP?

A. The 2024 and 2029 Bid Evaluation Case estimates of congestion and loss-related charges between the wind facilities proposed by the bidders who met the eligibility and threshold requirements of Section 9.1 of the Company's RFP and the AEP West load zone are discussed in Company witness Sheilendranath's testimony and summarized in Table 2

[8] The company assumed that the Cleveland 138 kV bus-tie, located west of Tulsa, will be addressed by an SPP solution in the near term since it was identified by SPP as both an economic and operational need in the 2019 ITP Study and the transmission upgrade costs were expected to be low.

below. This summary includes annual averages that are weighted by the hourly MWh output of each RFP Wind Facility.[9] To discuss the reasonableness of the Company's RFP bid-evaluation process, I have also included congestion and loss estimates for wind generation proposals that did not meet the FCITC threshold requirements in Section 9.1.12 of the Company's RFP.

To allow for a comparison to the simple average of historical congestion costs discussed earlier, Table 2 summarizes both the simple average of congestion and loss-related costs across all hours of the year as well as the wind-generation-weighted average. As shown in the table, the wind-generation-weighted average of annual congestion charges, which more closely represents the congestion cost that the Company and its customers would pay under the simulated market conditions, tends to be higher than the simple average by a factor of approximately two. This is because congestion is typically higher when wind generation output is higher.

[9] These average congestion and loss-related costs include the full congestion charge (not considering any TCR congestion hedges) and half the marginal losses charge (reflecting that SPP refunds approximately half of its marginal loss revenues because average line losses are half of marginal line losses).

Table 2: Simulated Wind-to-AEPW Congestion and Loss Costs for RFP Bids
(Bid Evaluation Case, $/MWh)

		2024				2029			
		Simple Avg		Gen-Wtd Avg		Simple Avg		Gen-Wtd Avg	
Company Bid Ranking	Bid Number	Congestion [A]	Losses [B]	Congestion [C]	Losses [D]	Congestion [E]	Losses [F]	Congestion [G]	Losses [H]
Average		*7.08*	*0.78*	*12.95*	*1.19*	*7.97*	*1.06*	*14.07*	*1.54*
P1*	21	6.75	0.65	12.02	1.02	8.04	0.90	13.75	1.32
P2*	15	5.78	0.79	11.33	1.36	5.80	1.05	11.50	1.70
P3*	17	6.14	0.93	13.16	1.54	6.77	1.20	13.86	1.90
P4	12	10.43	1.15	15.71	1.55	12.00	1.53	17.82	2.00
P5	1	5.91	0.46	10.45	0.87	7.37	0.72	12.48	1.18
P6	6	8.22	0.70	15.64	1.14	8.71	0.94	16.10	1.44
P7	4	7.94	1.16	14.29	1.63	9.35	1.58	16.25	2.14
P8	30	7.29	0.91	13.19	1.33	8.64	1.25	15.07	1.74
P9	2	8.19	1.29	14.53	1.79	9.63	1.73	16.46	2.34
P10	31	9.55	0.72	19.28	0.94	8.49	0.94	16.16	1.16
P11	32	10.69	0.92	19.75	1.36	10.54	1.16	20.19	1.59
P12**	3	3.43	0.27	6.01	0.62	4.24	0.43	6.91	0.82
P13**	29	8.07	1.31	14.99	1.83	9.39	1.76	16.86	2.38
P14**	33	3.50	0.26	6.11	0.60	4.42	0.41	7.22	0.81
P15**	34	4.36	0.20	7.71	0.34	6.20	0.36	10.46	0.52

Source and Notes:

*Unit is one of the three selected units

**Units reported for informational purposes as they were disqualified from the Companies' evaluation based on deliverability.

2024 and 2029 PROMOD simulation outputs for Bid Evaluation Case.

[B] & [D] & [F] & [H]. Average loss costs represent half of the wind-generation-weighted marginal loss charges for the wind resources.

Q. ARE THESE CONGESTION FORECASTS REASONABLE FOR THE PURPOSE OF BID EVALUATION?

A. Yes, they are reasonable for the simulated market conditions, which includes significant amounts of added wind generation without SPP transmission investments beyond the interconnection-related upgrades. While the absolute levels of the simulated congestion costs in this bid evaluation case may be higher than likely outcomes in a future where SPP further expands its transmission system, these congestion results are reasonable for the purpose of assessing congestion costs and risks of the different bids *relative* to each other.

Q. THE COMPANY HAS EVALUATED THE COST OF MITIGATING UNEXPECTEDLY HIGH CONGESTION. IS IT REASONABLE TO CONSIDER THE COSTS OF CONGESTION MITIGATION IN THE EVALUATION OF THE RFP BIDS?

A. Yes, it is. As illustrated in Table 1 and discussed earlier in my testimony, congestion costs are uncertain and can vary significantly both over time and across locations. They can be lower than currently projected if less wind generation is developed in certain locations or if SPP transmission upgrades exceed current expectations. But they can be much higher than currently projected—particularly in certain locations—if more wind generation is added to the system, if SPP is not able to upgrade transmission to relieve high congestion costs (or do so in a timely fashion), or if increases in fuel and generation costs increase the cost of congestion relief. Because not all of the congestion costs can be hedged through SPP-allocated Transmission Congestion Rights (TCRs), unexpected increases in congestion costs could increase the total cost of the delivered wind generation. If the Company is able to reduce this risk of unexpectedly high future congestion costs—such as through the construction of a generation tie or other transmission upgrades—analyzing the option to do so is valuable from a total customer cost and risk perspective.

In short, the unpredictability of future congestion costs is a risk that warrants consideration of options to manage if they were to manifest in the future. Therefore, it is advisable and reasonable that the availability and cost of congestion mitigation is used as one of the criteria in project selection as the Company has done.

Q. WAS IT REASONABLE TO USE A 50% WEIGHTING FOR EACH OF CONGESTION COST AND CONGESTION MITIGATION COST IN THE COMPANY'S CALCULATION OF LACOE?

A. Yes. As discussed below, the bid selection results are also robust across a range of alternative weights.

Q. WHAT WAS THE COMPANY'S FINAL SELECTION OF PROJECTS AND IS THAT SELECTION REASONABLE?

A. PSO and SWEPCO selected three wind facilities, amounting to approximately 1,500 MW in total, by applying the evaluation methodology outlined in Sections 9.1 and 9.2 of the RFP sections. I have reviewed the selections based on the methodology outlined, focusing on the costs of each individual bid, the congestion costs estimates developed for each bid, the deliverability of wind generation within each cluster of bids, as well as the consideration of congestion mitigation option costs. Based on my review, I find the selection process was comprehensive and consistent with the methodology outlined in its RFP. I also find that the selections are reasonable and robust across a range of alternative economic selection criteria that could have been applied. The Selected Wind Facilities represent the most economic bids that simultaneously offer the lowest congestion costs and lowest congestion risks.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW YOU ARRIVED AT THE CONCLUSION THAT THE SELECTIONS ARE REASONABLE AND ROBUST ACROSS A RANGE OF ALTERNATIVE ECONOMIC SELECTION CRITERIA.

A. To arrive at the conclusion that the Selected Wind Facilities represent an economically reasonable choice that is optimal in terms of overall costs and risk, I have evaluated the bids across a range of alternative selection criteria. Table 3 below demonstrates the robustness of the cost- and risk-minimizing properties of the Selected Wind Facilities. I have assessed the relative economics of the Selected Wind Facilities (shown by their project names and in **bold**) that the Company chose based on its selection criterion (shown as "Criterion 4" in the table) against four other possible selection criteria. As I will explain, the Selected Wind Facilities perform well across all of the five different sets of criteria tested:

Criterion 1: Project Cost only (*i.e.*, only the Levelized Cost of Energy or LCOE)
Criterion 2: Project Cost + Congestion (including losses)
Criterion 3: Project Cost + Gen-Tie Cost (proxy for cost of congestion risk mitigation)
Criterion 4: Project Cost + 50% Congestion + 50% Gen Tie (as used by Company)
Criterion 5: Project Cost + 75% Congestion + 25% Gen Tie

Table 3 highlights in shading the lowest-cost portfolio of approximately 1,500 MW of wind facilities for each of the five criteria. Table 3 shows that the three Selected Wind Facilities (shown in **bold***):

1. Are the lowest-cost option for the Company's criterion (Criterion 4) and the alternative Criterion 5. Specifically, the Selected Wind Facilities are lowest-cost portfolio for the Company's "Criterion 4" (with 50% weight to the cost of a gen-tie as a proxy for the available congestion risk mitigation options) and for "Criterion 5" (which applies only a 25% weight to the gen-tie risk mitigation option).
2. Offers total costs that are very close to and generally within the range of lowest-cost portfolios when using each of the other selection criteria 1, 2 and 3. For example, the average cost of the three Selected Wind Facilities is only slightly above the lowest cost portfolio if only the project cost itself were considered (Criterion 1) or if only project cost and estimated congestion were considered (Criterion 2) without considering the cost of mitigating congestion risk.
3. Offers total costs that are substantially below the least-cost portfolios derived from Criteria 1 and 2, if congestion increased unexpectedly and needed to be mitigated in the future.

Table 3: Assessment of Wind Facilities Selection with Alternative Selection Criteria
("Criterion 4" = Company Bid Selection Criterion)

Criterion 1: Project Cost Only		Criterion 2: Project Cost + Congestion		Criterion 3: Project Cost + Gen Tie		Criterion 4: Project Cost + 50% Congestion + 50% Gen-Tie		Criterion 5: Project Cost + 75% Congestion + 25% Gen-Tie	
Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost	Bid Number	% of Lowest Cost
2	100%	3*	100%	**Traverse (21)**	100%	**Traverse (21)**	100%	**Traverse (21)**	100%
Sundance (17)	121%	2	114%	**Maverick (15)**	106%	**Maverick (15)**	102%	**Maverick (15)**	100%
12	126%	1	117%	6	107%	**Sundance (17)**	106%	**Sundance (17)**	101%
4	129%	**Sundance (17)**	119%	**Sundance (17)**	116%	12	113%	1	105%
Maverick (15)	132%	**Maverick (15)**	121%	12	121%	1	115%	12	109%
Traverse (21)	133%	**Traverse (21)**	124%	1	139%	6	121%	4	117%
1	133%	4	130%	30	147%	4	129%	2	118%
32	135%	33*	130%	4	156%	30	133%	30	126%
3*	135%	12	131%	31	180%	2	145%	6	128%
29*	160%	34*	141%	2	204%	31	157%	32	138%
30	163%	32	146%	32	207%	32	160%	31	146%
31	184%	30	149%						
33*	185%	29*	155%						
34*	189%	6	166%						
6	189%	31	168%						
Capacity Weighted Average of Lowest Costs 1,500 MW	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**	**Capacity Weighted Average of Lowest Costs 1,500 MW**	**100%**
Capacity Weighted Average of Selected Wind Facilities	**107%**	**Capacity Weighted Average of Selected Wind Facilities**	**104%**	**Capacity Weighted Average of Selected Wind Facilities**	**101%**	**Capacity Weighted Average of Selected Wind Facilities**	**100%**	**Capacity Weighted Average of Selected Wind Facilities**	**100%**
				Weighted Average of Lowest Cost 1,500 MW in Criterion 1	**140%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 1**	**118%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 1**	**108%**
				Weighted Average of Lowest Cost 1,500 MW in Criterion 2	**155%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 2**	**124%**	**Weighted Average of Lowest Cost 1,500 MW in Criterion 2**	**110%**

Source and Notes:

*Unit was disqualified from Company's evaluation based on deliverability.

Named units represent the Company's Selected Wind Facilities.

Lowest Cost 1,500 MW in each ranking are highlighted blue.

Capacity, LCOE, LCOC, and Gen-Tie costs come from AEP's RFP IE Briefing, dated April 16, 2019.

Capacity weighted average of lowest-cost 1,500 MW portfolios for Criterion 1 and Criterion 2 shown under the Criteria 3, 4, and 5 columns calculated using the project cost and the respective Criteria 3, 4, and 5 congestion and gen-tie assumptions. For gen-tie costs, costs developed by Independent Evaluator of Oklahoma Corporation Commission is used for units disqualified from Company's evaluation based on deliverability.

For example, if congestion were ignored entirely, the results in the "Criterion 1" (project cost only) panel of the table show that the average levelized project cost of the Selected Wind Facilities is only 7% above the cost of a 1,500 MW portfolio with the lowest project costs (not considering congestion). This is reflected in the bottom half of the table, comparing the costs of the lowest cost projects that would accumulate to 1,500MW (under each criterion) against the costs of the three selected facilities. The calculations on the bottom half of the table show that the Selected Wind Facilities would cost 4% more than the lowest cost 1,500 MW portfolio, if Criterion 2 were used (without considering congestion risk mitigation).

Moving to the right in the Table 3, the bottom half of the table shows the relative costs of the Criterion 1 portfolio (shown as the shaded resources in the first column) and Criterion 2 portfolio (shown as the shaded resources in the second column) are respectively 40% and 55% more costly than the Selected Wind Facilities if Criterion 3 (high congestion costs that need to be mitigated) is used for evaluating the projects. Based on these calculations, Table 3 shows that the portfolio with the lowest project costs (based on Criterion 1) is significantly more costly than the Selected Wind Facilities if congestion mitigation became necessary and a gen-tie would need to be built (Criterion 3). The calculations show that the facilities with the lowest project costs (under Criterion 1) would have a delivered cost that is *40% above* those of the Selected Wind Facilities' delivered cost. The same is true if the lowest-cost portfolio based on Criterion 2 (congestion and loss-related costs added to the project costs, without considering congestion risk mitigation) faced a future in which congestion mitigation becomes necessary (Criterion 3). As shown, if congestion mitigation became necessary (Criterion

3), the cost of the portfolio selected solely based on Criteria 2 would be *55% above* the cost of the Selected Wind Facilities.

The comparisons in Table 3 show that for a very modest amount (4 to 7%) above the lowest project costs with or without estimated congestion costs (Criteria 1 or 2), the Selected Wind Facilities offer a very valuable protection against the risk of higher-than-expected congestion costs (Criterion 3). Unlike the other possible portfolios of wind projects, the Selected Wind Facilities thus offer a more robust portfolio that is much less exposed to unexpected future increases in congestion costs. This is not surprising considering that the three Selected Wind Facilities are located relatively close to the Company's Tulsa load center, which reduces congestion risk and facilitates lower-cost mitigation options—whether through a gen-tie or other transmission upgrades—in case such mitigation was needed in the future.

Finally, Table 3 shows that the portfolio of Selected Wind Facilities is optimal across a range of likelihoods that implementing the available congestion risk mitigation option would actually be necessary. Criterion 3 implies a 100% likelihood that a gen-tie would need to be built to mitigate congestion, Criterion 4 assumes a 50% chance that the congestion risk mitigation may become necessary (the Company's selection criteria), while Criterion 5 assumes only a 25% chance that risk mitigation may need to be implemented. As shown, the Selected Wind Facilities represent the least-cost choice for both Criterion 4 and 5.

Q. THE TWO COMPANIES INITIALLY CONSIDERED PROCURING UP TO A COMBINED 2,200 MW OF WIND GENERATION, BUT HAVE SELECTED

APPROXIMATELY 1,500 MW FROM THE RFP. WAS THAT DECISION REASONABLE?

A. Yes. As shown in the Company's economic selection criterion (Criterion 4 in Table 3, with a 50% weighting of estimated congestion and gen-tie costs), the delivered costs of the three Selected Wind Facilities are within 6% of each other. The selection would need to include the fourth, fifth, and sixth projects listed under Criterion 4 in Table 3 to reach 2,200 MW. However, the costs of these next three projects are significantly higher, ranging from 13% to 21% above the lowest-cost project. Given the high cost difference between the first three and the next set of three projects, it is reasonable to limit the procurement at 1,500 MW at this point in time.

VI. REASONABLENESS OF THE COMPANY'S BENEFITS ANALYSIS OF THE SELECTED WIND FACILITIES

Q. ONCE THE SELECTED WIND FACILITIES WERE CHOSEN, DID THE COMPANY FURTHER REFINE THE SPP PROMOD SIMULATIONS FOR THE PURPOSE OF ITS CUSTOMER BENEFITS ANALYSIS?

A. Yes. Once the Selected Wind Facilities had been identified, the Company further refined the SPP PROMOD Case to create a "Base Case" for its customer benefits analysis. To do so, three modifications were made to the "Bid Evaluation Case" discussed above. First, the Company considered likely SPP transmission upgrades by assuming that upgrades would be made, at a minimum, to address the transmission needs that SPP has already identified in the currently-ongoing ITP process.[10] Second, the updated

[10] As part of the ongoing 2019 ITP assessment, SPP posted a list of "2019 ITP Needs" which included economic needs in addition to reliability needs prior to the opening of the 2019 ITP Detailed Project Proposal response wind window or the "DPP Window". The Company used this list of SPP-ITP-

PROMOD Base Case assumes the three Selected Wind Facilities will be built and that transmission network upgrades that SPP identified and requires through its generation interconnection process for the Selected Wind Facilities would be built as well. From a generation assumption perspective, the revised Base Case retains all the wind facilities that SPP has added to its PROMOD Reference Case but does not include other wind generation bids beyond the three Selected Wind Facilities. This resulted in total installed wind generation that exceeds the SPP Reference Case by 1,000 MW to account for the Selected Wind Facilities not in the SPP Reference Case.[11]

Q. IS IT REASONABLE THAT THE COMPANY MADE THESE PROMOD CASE REFINEMENTS TO CONSIDER FUTURE SPP TRANSMISSION UPGRADES?

A. Yes. While modeling future SPP transmission upgrades for each bid was not necessary for assessing ***relative*** congestion-related costs and risks for the purpose of the RFP bid-evaluation process—and could have distorted the selection based on SPP upgrades not yet approved—assessing the impact of likely SPP transmission upgrades is important for the customer benefit analysis. This is because the customer benefit analysis requires an estimate of the likely overall ***level*** of congestion costs associated with delivering the Selected Wind Facilities to the AEP West load zone to ensure that the benefits that customers receive from these wind facilities are estimated accurately.

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identified transmission needs for the reference case and implemented the associated transmission upgrades by relieving the SPP-identified constraints in the simulations.

[11] The Company, again, also identified transmission constraints created by the Selected Wind Facilities to make sure these are monitored and enforced constraints in the PROMOD simulations.

Q. HAS THE COMPANY ANALYZED A CASE IN WHICH HIGHER CONGESTION WOULD MATERIALIZE IF THE SPP-ITP-IDENTIFIED TRANSMISSION NEEDS WERE NOT ADDRESSED?

A. Yes, given the uncertainty about the extent and timing of future SPP transmission upgrades, the Company has additionally run simulations with an SPP PROMOD case *without* upgrading (all but one) the SPP-ITP-identified transmission needs.[12] As would be expected, this "No-SPP-Upgrades Case" yields higher congestion charges than the "Base Case," given the lack of additional transmission upgrades. The No-SPP-Upgrade Case still yields lower congestion charges than what has been reflected in the Bid Evaluation Case, since the Bid Evaluation case includes an additional 3,400 MW of proposed wind projects that were not selected by the Company. As discussed in Company witness Torpey's testimony, the Company has used this No-SPP-Upgrades Case to evaluate customer benefits under a higher-congestion scenario in which it is assumed that congestion risk mitigation through a gen tie would become necessary.

Q. HOW DO THE PROJECTED 2024 AND 2029 CONGESTION ESTIMATES FROM THE SPP PROMOD MODEL COMPARE TO THE HISTORICAL CONGESTION LEVELS EXPERIENCED BY EXISTING WIND GENERATION IN SPP?

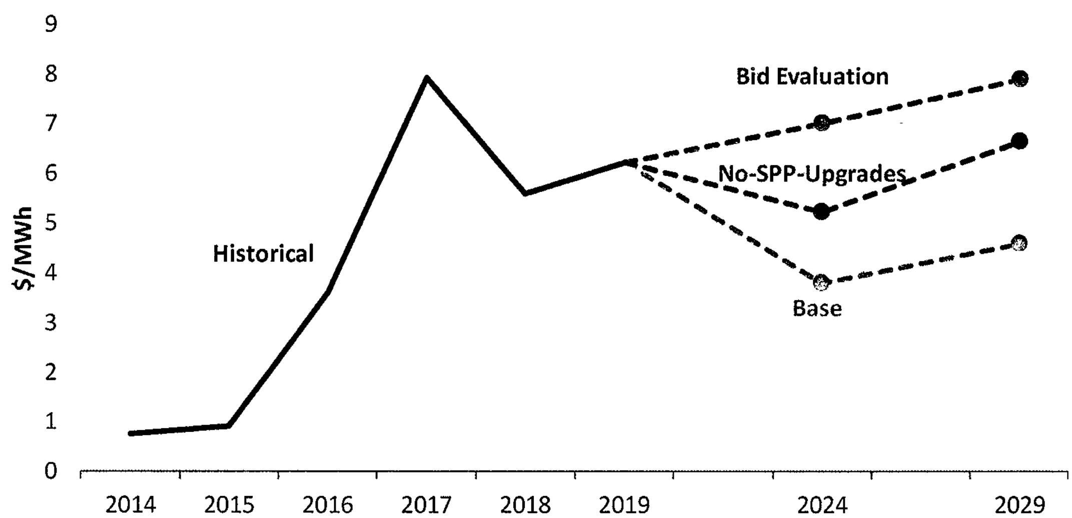
A. Figure 1 below summarizes the simple annual average of hourly congestion charges between the AEP's existing Oklahoma wind facilities and SPP's AEP-West load zone for both historical years (as previously reported in Table 1) and projected future years (as

[12] As noted earlier, the company assumed in all cases that the Cleveland 138 kV bus-tie, located west of Tulsa, will be addressed by an SPP solution in the near term since it was identified by SPP as both an economic and operational need in the 2019 ITP Study and the transmission upgrade costs were expected to be low.

simulated in PROMOD). More specifically, these simple averages[13] of wind-to-AEP West load zone congestion costs are shown both for: (1) the actual historical real-time market outcomes for 2014 through (year to date) 2019; and (2) the 2024 and 2029 simulations results for AEP's existing Oklahoma wind facilities from the Base, No-SPP-Upgrades, and Bid Evaluation PROMOD cases. As shown, the historical average annual congestion charges between AEP's existing Oklahoma wind plants and the AEP West load zone (solid black line) have ranged from a low of less than $1/MWh in 2014 and 2016 to $8/MWh in 2017, before dropping to around $6/MWh in 2018 and (year to date) 2019—reflecting the congestion-reducing effect of SPP transmission additions that came online in recent years. As shown, the simulated future congestion levels are in the upper half of the historically-experienced range.

[13] Again, because hourly historical wind generation data is not publicly available for these wind facilities, the figure presents the simple averages over all hours of the year. Although this will understate the actual congestion costs faced by the owners of these wind facilities (because hours with higher wind generation will tend to have higher congestion charges), the simple averages nevertheless document congestion trends over time and allow for a comparison of historical and simulated congestion levels.

Figure 1: Historical and Simulated Wind-to-AEPW Congestion for Existing AEP Wind Facilities in Oklahoma
(Simple all-hours annual average, weighted by MW plant size)



Looking forward, the figure shows the SPP PROMOD simulation results for the three congestion scenarios simulated by the Company.

1. The "*Bid Evaluation Case*" results from the 2024 and 2029 SPP PROMOD cases used for RFP bid evaluation (the highest dashed line) show the highest simulated congestion charges because the case includes all wind facility bids received by the Company and reflects only transmission upgrades that SPP has identified in the modeled wind facilities' interconnection studies. As shown, these simulation results are at the high end of the historical range for existing Oklahoma wind facilities.
2. The "*Base Case*" simulation results for the 2024 and 2029 SPP PROMOD cases used for the customer benefit analysis (the lowest dashed line) show the lower congestion charges, reflecting (a) the addition of only the Selected Wind Facilities (beyond the wind facilities already in the SPP case), (b) transmission upgrades that SPP has identified in the Selected Wind Facilities' interconnection studies; as well as (c) the assumption that SPP would upgrade the transmission constraints it has identified through the currently-ongoing SPP ITP stakeholder process. As shown, the 2024 and 2029 results for this simulation show congestion charges that are approximately the average of historical congestion, reflecting the congestion-reducing impact of the assumed upgrades of the SPP-ITP-identified transmission constraints.
3. Finally, the "*No SPP Upgrades Case*" used by the Company for conducting the Customer Benefit Analysis (the middle dashed line) shows congestion

results below those of the bid evaluation case but above the base case. As discussed further below, this higher-congestion case was used for Company witness Torpey's congestion risk mitigation scenario of the customer benefit analysis. This case shows congestion charges that are lower than the bid evaluation case, because only the three Selected Wind Facilities (*i.e.*, not all received bids) have been added beyond the wind additions reflected in the SPP cases. The congestion charges are above the Base Case results because this case assumes that, beyond the already-approved upgrades, none of the current SPP-ITP-identified transmission needs would be addressed—which, compared to the Base Case, would make it more likely that the congestion risk mitigation option evaluated by Company witness Torpey would need to be implemented.

Q. IS IT REASONABLE THAT 2024 CONGESTION LEVELS FOR THE BASE CASE WOULD BE BELOW THOSE RECENTLY EXPERIENCED?

A. Yes, it is. All SPP-approved transmission upgrades that are currently under development will be placed into service by the 2024 simulation year. This involves over $1.6 billion of transmission upgrades in 2019 through 2024.[14] Because the Base Case simulation further assumes that the additional transmission needs SPP has identified in its current ITP assessment would be addressed through additional upgrades as well, it is reasonable that congestion would be reduced below the recent historical levels.

Q. WHY IS CONGESTION INCREASING BETWEEN 2024 AND 2029 IN ALL THE SIMULATION CASES?

A. The estimated congestion level increases between 2024 and 2029. However, only a small portion of that increase will relate to additional wind generation development because SPP assumes that only 400 MW new wind facilities become operational between 2024 and 2029 based on SPP Reference Case. Thus, much of the higher congestion charges are driven by higher generation redispatch costs. To illustrate this point, the simple

[14] See page 8 of Second Quarterly Project Tracking Report, April 2019 https://www.spp.org/documents/59868/q2%202019%20spp%20quarterly%20project%20tracking%20report.pdf

average of monthly gas prices in the SPP Reference Case is $4.62/MMBtu in 2024 and is $5.44 in 2029, a 17.8% increase. Since congestion increases by 21.9% between the two years of the No-SPP-Upgrades Case, it suggests that the dominant driver of the shown congestion charge increase is accounted for by higher gas prices, which increase the redispatch cost. The other effects are likely accounted for by a combination of the added wind generation, significant new solar generation, and the retirements of some of the aging fossil generating plants in SPP projected for 2029.

Q. IF CONGESTION COSTS WERE TO INCREASE ABOVE PROJECTED LEVELS, WOULD IT BE MORE LIKELY THAT SPP WOULD UPGRADE THE CONSTRAINED TRANSMISSION FACILITIES?

A. Yes. In general, as congestion costs associated with specific transmission facilities increase, it will at some point become either cost effective to upgrade the constraining transmission facilities or necessary to upgrade some of the constrained facilities from a system reliability perspective. Whether and when SPP would identify and approve such further upgrades is uncertain, however, which creates the congestion and deliverability risks that the Company has considered in its RFP bid evaluation process. If congestion increases but SPP transmission upgrades are not implemented to address the higher congestion, the likelihood increases that the Company will need to mitigate that congestion through dedicated transmission upgrades, such as a gen-tie between the Selected Wind Facilities and the Company's Tulsa load center, as evaluated by Company witness Torpey.

Q. ARE CUSTOMERS FULLY EXPOSED TO THE PROJECTED WIND-TO-LOAD CONGESTION CHARGES?

A. No, they are not fully exposed to the congestion charges. Load serving entities are able to obtain from SPP allocations of some Transmission Congestion Rights (TCRs) that allow them to avoid (hedge at no cost) a portion of these congestion charges in the day-ahead market. Unfortunately, due to limited transmission capability and the high levels of wind generation developed in the region, it has been difficult to obtain sufficient TCR allocations for wind facilities from SPP. In addition, some of the congestion is experienced only in the real-time market, which cannot be hedged through TCRs. As noted by Company witness Ali, the Company forecasts that approximately 25% of its wind generation-related congestion costs could be hedged. The benefit of these congestion hedges is not reflected in the congestion costs reported in the summary charts and tables of my testimony, nor are they considered in the congestion cost and risk analysis during the RFP bid evaluation process. They are, however, reflected in the Company's customer benefits analysis (at the 25% hedge ratio).

Q. WHAT ARE THE SPP PROMOD ESTIMATES OF FUTURE CONGESTION AND LOSS-RELATED COSTS FOR THE SELECTED WIND FACILITIES BEFORE AND AFTER CONSIDERING THE LIKELY UPGRADES OF THE SPP-ITP-IDENTIFIED TRANSMISSION CONSTRAINTS?

A. Table 4 below shows congestion and loss-related costs for the Selected Wind Facilities based on the PROMOD results for the Base Case and No-SPP-Upgrades Case simulations.

Table 4: Simulated Wind-to-AEPW Congestion and Losses for the Three Selected Wind Facilities

($/MWh)	2024				2029			
Selected Wind Facility	**Simple Avg**		**Gen-Weighted Avg**		**Simple Avg**		**Gen-Weighted Avg**	
	Congestion	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**	**Congestion**	**Losses**
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
Base Case								
Average	*3.87*	*0.76*	*7.43*	*1.33*	*4.83*	*1.01*	*9.15*	*1.67*
Traverse	4.17	0.61	7.81	1.02	5.40	0.85	10.02	1.31
Maverick	3.31	0.73	6.30	1.35	4.05	0.97	7.61	1.68
Sundance	4.14	0.94	8.18	1.63	5.03	1.21	9.81	2.01
No-SPP-Upgrades Case								
Average	*4.85*	*0.74*	*9.25*	*1.28*	*6.15*	*0.98*	*11.27*	*1.60*
Traverse	7.05	0.59	12.80	0.98	8.94	0.82	15.69	1.26
Maverick	3.02	0.71	6.01	1.30	3.74	0.95	7.20	1.62
Sundance	4.47	0.91	8.94	1.56	5.78	1.16	10.94	1.92

Source and Notes:
2024 and 2029 PROMOD simulation outputs.
[B] & [D] & [F] & [H]· Average loss costs represent half of the wind-generation-weighted marginal loss charges for the wind resources.

Q. PLEASE SUMMARIZE THE OVERALL METHODOLOGY AND METRICS THE COMPANY USED FOR ITS CUSTOMER BENEFITS ANALYSIS.

A. As explained in the testimony of Company witness Torpey, the Company analyzed customer benefits associated with the three Selected Wind Facilities for thirteen cases covering a range of wholesale power market fundamentals (provided by Company witness Bletzacker), wind availability cases (provided by Company witness Godfrey), congestion risk mitigation cases, and a break-even case (estimated by Company witness Torpey). These include customer benefits for 50th percentile (P50) annual wind generation for the following five wholesale-power-market fundamentals using the Base Case PROMOD congestion estimates:

1. a "base-gas/with-carbon" case (as the Company's base fundamentals case)
2. a "base-gas/no-carbon" case
3. a "low-gas/with-carbon" case
4. a "low-gas/no-carbon" case
5. a "high-gas/with-carbon" case

In addition to these five P50 cases reflecting Company witness Bletzacker's market fundamentals forecasts, the Company also developed four additional cases based on the five-year 95th percentile (P95)[15] wind production levels. As further explained by Company witness Torpey, these four P95 cases (also using the Base Case PROMOD congestion estimates) include:

6. a P95 case for "base-gas/with-carbon" market fundamentals
7. a P95 case for "base-gas/no-carbon" market fundamentals
8. a P95 case for "low-gas/with-carbon" market fundamentals
9. a P95 case for "high-gas/with-carbon" market fundamentals

As explained further by Company witness Torpey, an additional three cases were developed to evaluate customer benefits in a higher congestion scenario (using the "No-SPP-Upgrades" PROMOD congestion case) under which a generation tie line could be built cost effectively to mitigate the higher congestion costs. These three "Gen-Tie" cases include:

10. a P50 gen-tie case for "base-gas/with-carbon" market fundamentals
11. a P50 gen-tie case for "base-gas/no-carbon" market fundamentals
12. a P95 gen-tie case for "base-gas/no-carbon" market fundamentals

[15] Note that applying the 5-year P95 wind capacity values to the 30-year customer benefit analysis yields a conservatively low P95 estimate of 30-year customer benefits because the probability of achieving wind generation better than the 5-year P95 level is greater than 95% over a 30-year period (i.e., six consecutive five-year P95 low-wind periods).

And finally, to estimate how low natural gas prices and associated wholesale power market prices could be while still producing customer benefits sufficient to cover the Selected Wind Facilities' costs, Company witness Torpey also developed:

13. a "break even" case

Company witness Bletzacker also developed for this break-even case (reflecting P50 wind conditions) a break-even natural gas price estimate.

Q. HOW HAS COMPANY WITNESS TORPEY DETERMINED CUSTOMER BENEFITS?

A. As Company witness Torpey explains, he has used the Company's PLEXOS model to determine how the Company's energy- and capacity-related costs—including its generation dispatch, off system sales and wholesale market purchases—will be affected by the ownership and operation of the Selected Wind Facilities. PLEXOS simulates these costs separately for PSO and SWEPCO. To determine these PSO and SWEPCO net customer costs, PLEXOS uses as an input the wholesale power market prices for the AEP West load zone, PSO and SWEPCO conventional generation, as well as the congestion and loss costs associated with deliveries from the Selected Wind Facilities.

As Company witness Torpey explains, the customer benefits of purchasing the Selected Wind Facilities are then determined by comparing the (1) total customer costs *with* the purchase of the Selected Wind Facilities; to the (2) total customer costs *without* the purchase of the Selected Wind facilities.

Q. HOW DID THE COMPANY DETERMINE THE WHOLESALE-POWER MARKET PRICES AND CONGESTION-COST INPUTS FOR PLEXOS?

A. The Company used the wholesale power market prices from it "markets fundamentals forecasts," which are based on Company witness Bletzacker's wholesale power market simulations for the entire Eastern Interconnection, covering the eastern two-thirds of the United States. As Company witness Bletzacker explains in his testimony, these simulations with the Aurora Energy Market Simulation Model (AURORA) provide a wholesale market price forecast for the "SPP Central" region, but do not further differentiate wholesale power prices by location or simulate congestion costs within SPP. Since the congestion and loss-related costs of delivering power from the Selected Wind Facilities had to be considered, it was necessary to develop for each AURORA simulation of the market fundamentals forecast: (1) a consistent set of estimated congestion and loss costs of delivering wind generation from the Selected Wind Facilities; and (2) an estimate of how market prices for the AEP West load zone and PSO and SWEPCO conventional generation differ locationally from the larger "SPP Central" zone price simulated in AURORA.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY CONGESTION AND LOSS COSTS FOR ITS AURORA-BASED FUNDAMENTALS PROJECTIONS FOR SPP CENTRAL?

A. The Company has utilized its PROMOD locational market simulations to estimate congestion and loss costs as well as the locational differences in SPP wholesale market prices. I have previously explained how congestion and loss costs were projected using the SPP PROMOD Reference Case as modified by the Company for wind generation additions and transmission upgrades. As explained in the testimony of Company witness Sheilendranath, these PROMOD congestion and loss-related costs had to be scaled to the various AURORA-based market fundamentals forecasts in proportion to the difference between (1) the SPP Central prices in the PROMOD simulations and (2) the SPP Central prices from the AURORA-based market fundamentals cases listed earlier.

Q. WHY WAS IT NECESSARY AND REASONABLE TO COMBINE MULTIPLE MODELS—PROMOD, AURORA, AND PLEXOS—TO ESTIMATE CUSTOMER BENEFITS ASSOCIATED WITH THE THREE SELECTED WIND FACILITIES?

A. PROMOD, AURORA, and PLEXOS are simulation tools that can be employed to perform the type of forward-looking market simulations necessary to assess the benefits of the Selected Wind Facilities. However, in this case, all three simulation tools were necessary for a number of reasons.

The Company has been relying on AURORA to project long-term trends of multi-regional market prices and PLEXOS for analyzing the market performance of their individual Company resources and for evaluating expected market revenues and dispatch outcomes for resource planning and customer impact purposes. Relying on AURORA for projecting long-term trends of regional market prices is advantageous because AURORA employs a consistent set of market fundamentals assumptions, such as natural gas and coal prices, for the full range of long-term wholesale power market and fuel price scenarios that AEP companies use for all their long-term planning purposes across all of their service areas. The Company uses these AURORA-based fundamentals forecasts for a variety of resource planning purposes as explained by witness Bletzacker.

Relying on PLEXOS to estimate customer impacts for individual operating companies has several advantages. The model is set up to simulate many years of future market performance quickly and to link and provide input to customer rate impact assessments. Most importantly, unlike PROMOD, the PLEXOS model is set up to simulate PSO and SWEPCO individually, and therefore is able to assess changes in production costs, market purchase costs, off-system sales revenues, and other customer cost items at the operating-company level.

Unlike PROMOD, the AURORA and PLEXOS models are not set up to simulate transmission constraints or losses within the SPP footprint, which means they are unable to assess the extent to which wholesale power prices, congestion costs, and loss-related costs affect the delivered costs of generating resources, including the Selected Wind Facilities.

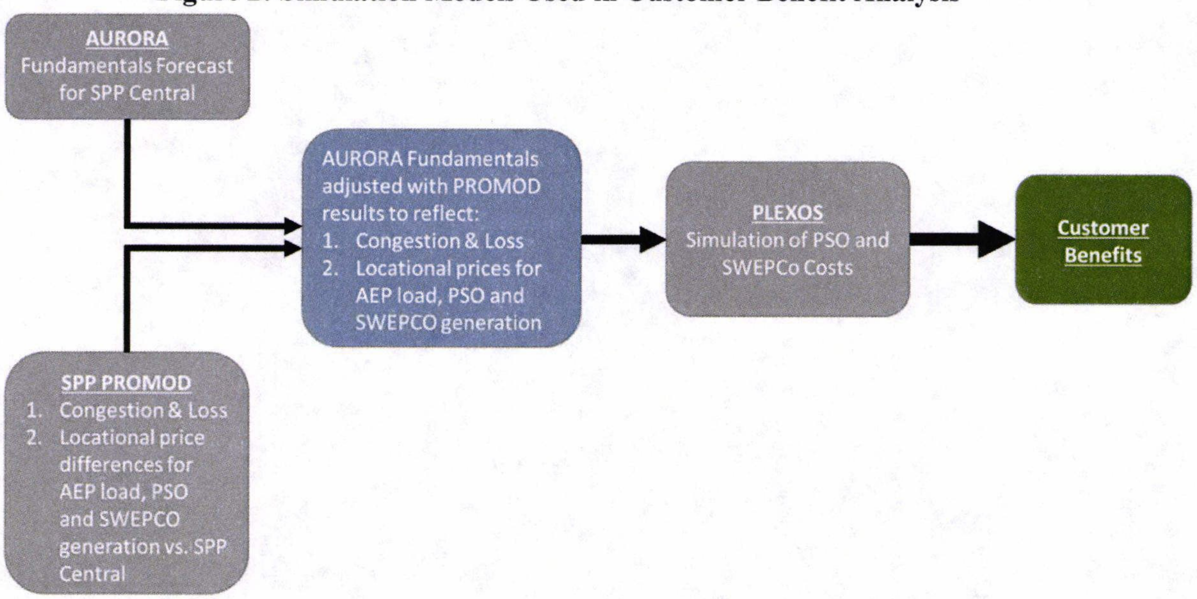
SPP's PROMOD models, as described earlier, simulate the entire SPP system (and surrounding market areas), including the full SPP transmission network and associated transmission constraints and losses. As stated previously in my testimony, transmission constraints have a significant effect on optimal SPP-wide market dispatch outcomes and the associated locational prices. Given that the large levels of wind generation are expected to grow further in the SPP region, it is important to capture the congestion and loss impacts of the transmission network on locational prices when evaluating the delivered costs of wind facilities. SPP's PROMOD model is, however, limited by the fact that it has been set up to analyze load-related impacts only for individual SPP transmission zones—such as the AEP West load zone, which aggregates both AEP companies (PSO and SWEPCO) as well as other public power entities—and without the level of detail that is required to separately assess customer impacts for each of the two AEP operating companies. In addition, SPP's PROMOD models are not conducive to quickly analyzing various sensitivities such as under varying long-term gas and coal price forecasts, and/or sensitizing with future carbon tax assumptions. The Company's AURORA model produces long-term regional price trends under varying sensitivities. Assessing the customer benefits under various market fundamentals sensitivities is essential for a comprehensive evaluation of the costs and benefits of the Selected Wind Facilities. Therefore, to assess the full benefits of the Selected Wind Facilities over the entire 30-year design lives and for each of the two companies, AURORA and PLEXOS were employed in conjunction with SPP's PROMOD models to capture the impact on the individual operating companies and to estimate the delivered cost and customer impact of the facilities.

Q. HOW HAS THE COMPANY DEVELOPED THE NECESSARY PLEXOS LOAD AND GENERATION MARKET PRICE INPUTS FROM ITS AURORA-BASED FUNDAMENTALS PROJECTION FOR SPP?

A. The Company's AURORA market fundamentals forecasts are for the AURORA-defined "SPP Central" zone. The PROMOD simulations were then used to estimate the extent to which the wholesale market prices for the AEP West load zone, PSO conventional generation, and SWEPCO conventional generation differed from market price projections for the SPP Central zone.

As explained in Company witness Sheilendranath's testimony, this was accomplished by scaling the PROMOD-based wholesale market price differences between SPP Central and the AEP load and generation locations based on the extent to which the level of market prices for SPP Central differ between the AURORA and PROMOD simulations. This scaling of PROMOD-based congestion and loss differences between SPP Central and AEP West load and the PSO and SWEPCO generation zones recognizes the SPP locational market price differences relative to SPP Central, but scales those differences up or down to be consistent with the extent to which AURORA market price forecasts for SPP Central are higher or lower than those for SPP Central in the SPP PROMOD simulations. How AURORA and PROMOD simulation results were combined by Company witness Sheilendranath to develop the necessary PLEXOS inputs is illustrated in Figure 2 below.

Figure 2: Simulation Models Used in Customer Benefit Analysis



Q. IS IT REASONABLE TO SCALE THE PROMOD CONGESTION AND LOCATIONAL MARKET PRICE DIFFERENTIAL BETWEEN AEP LOCATIONS

AND SPP CENTRAL BASED ON THE LEVEL OF AURORA MARKET FUNDAMENTALS?

A. Yes, it is. Given a certain transmission network and installed generation base in SPP, the congestion and loss-related costs will primarily be a function of the overall level of market prices. If natural gas prices are higher, for example, not only will overall wholesale power prices be higher, but the cost of supplying losses and redispatching generation to manage congestion within the SPP footprint will be correspondingly higher as well. Since the difference in wholesale market prices between different locations in SPP is a direct function of congestion and loss-related charges, it is reasonable to scale the differences in locational market prices with the overall level of market prices.

Q. WHAT ARE THE PROMOD MARKET PRICE DIFFERENCES BETWEEN SPP CENTRAL AND THE AEP WEST LOAD ZONE?

A. As shown in Table 5 below, the simple average of wholesale power prices (locational marginal prices or LMPs) for the AEP West load zone are \$4–\$7/MWh above simulated SPP-Central[16] prices across the three sets of PROMOD simulations used by the Company. As shown, the simulations with higher average wind-related congestion levels (*e.g.*, the No-SPP-Upgrades Case) also result in higher congestion-related wholesale market price differences between AEP load and generation and the SPP-Central region. Similar market price differences exist between SPP Central and the market prices faced by the Company's conventional generating units.

[16] As further discussed in the customer benefits analysis, which relies on the Company's AURORA-based fundamentals forecast, the SPP-Central zone in PROMOD closely matches the SPP-Central zone in AURORA.

Table 5: PROMOD LMP Difference between SPP Central and AEP-West Load Zone

	Base Case		No-SPP-Upgrades Case		Bid Evaluation Case	
Simple Average LMP ($/MWh)	2024	2029	2024	2029	2024	2029
SPP Central	$28.94	$34.32	$28.06	$33.37	$25.80	$31.09
AEP West Load	$32.46	$38.75	$32.24	$38.90	$31.73	$38.15
AEP Load to SPP Central Differential	$3.52	$4.43	$4.17	$5.53	$5.93	$7.06

Q. WHAT ARE THE COMPANY'S CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS?

A. The results of the Company's Customer Benefit Analysis are summarized in Company witness Torpey's testimony. As he shows, and as I summarize in my discussion of Figure 3 below, the benefits to SWEPCO customers of developing the Selected Wind Facilities are quite significant, with 31-year present values of SWEPCO customer benefits that exceed project costs by an amount ranging from approximately $200 million to $400 million under low gas or P95 low wind conditions, to $550 million to $700 million under high gas price, or high-congestion conditions. As Company witness Torpey explains, benefits include lower power purchase costs (net of changes in off system sales), the avoided costs of deferring conventional generation capacity needs, and the Company's ability to take advantage of the federal production tax credit. Costs include the revenue requirement of the Selected Wind Facilities, and the congestion and loss costs associated with delivering the output from the facilities to the AEP load zone. Company witness Torpey's gen-tie (congestion risk mitigation) cases include the additional benefits of avoided (higher) congestion costs but with the added cost of the gen tie.

Q. ARE THESE CUSTOMER BENEFIT METRICS AND BENEFITS RESULTS REASONABLE?

A. Yes, they are.

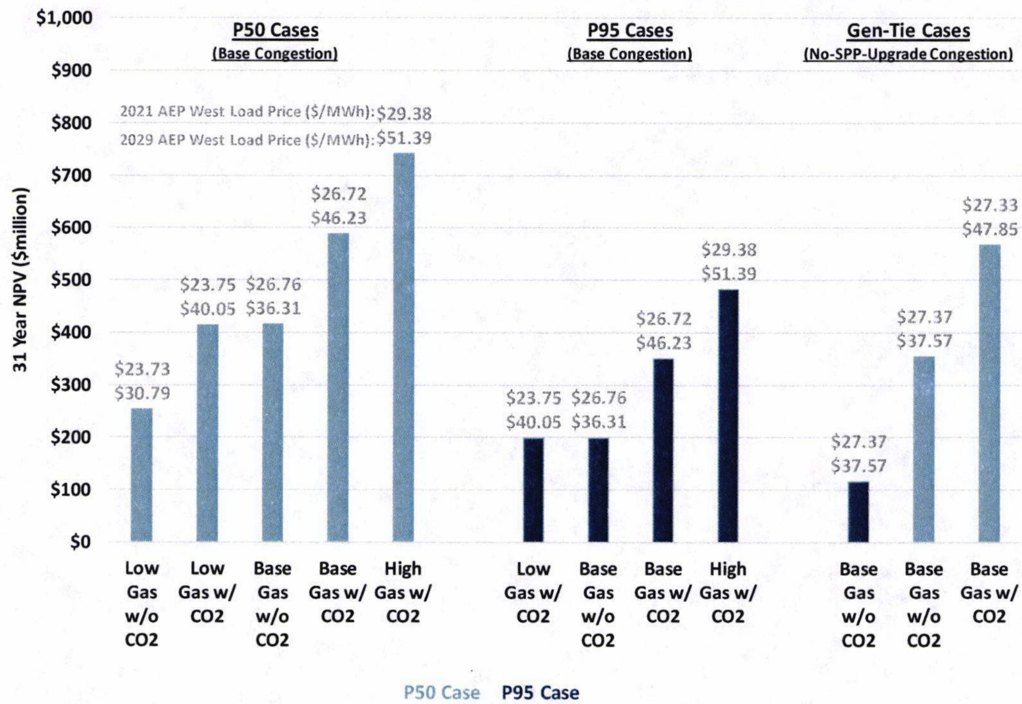
Q. DO YOU AGREE WITH THE BREAK-EVEN ANALYSIS PRESENTED BY THE COMPANY? PLEASE EXPLAIN.

A. Yes, I do. The Company's break-even analysis undertaken by Company witness Torpey starts with the Company's *lowest* whole power price fundamentals forecast (based on the "low-gas/no-carbon" case) to calculate the net present value of customer benefits. The wholesale power prices for the AEP load zone are then decreased in every year until the net present value of customer benefits is zero, as discussed in Company witness Torpey's testimony. Company witness Bletzacker then calculates the break-even natural gas price based on Company witness Torpey's break-even wholesale power price and the SPP "market heat rate" for the low-gas/no-carbon case. This is a reasonable approach for estimating how low SPP wholesale power prices and natural gas prices would need to fall before the present value of benefits are exactly equal to the present value of costs, such that the net benefit is zero—which means the Selected Wind Facilities just break even with benefits covering costs.

Q. WHAT DO THE BREAK-EVEN ANALYSIS AND THE VARIOUS MARKET FUNDAMENTALS CASES INDICATE AS THEY APPLY TO CUSTOMER BENEFITS, COSTS, AND RISKS?

A. Company witness Torpey's break-even and customer benefit analyses show that the Selected Wind Facilities offer significant customer benefits and that these benefits are robust across a wide range of market fundamentals. The analyses also show that in futures in which higher congestion charges would otherwise diminish customer benefits, the ability to mitigate these congestion-related effects through transmission investments (such as a gen tie) safeguards these customer benefits. The results of the customer benefits analyses are summarized for SWEPCO in Figure 3 below, with each bar indicating the net present value of customer benefits for one of the 12 cases simulated. The lightly-shaded bars (sorted from lowest to highest customer benefits) represent P50 wind generation cases, while the dark bars represent the P95 low-wind generation cases. The dollar numbers above the bars indicate (for informational purposes) the 2021 and 2029 wholesale power price for the AEP load zone in each of these cases.

Figure 3: Summary of SWEPCO Customer Benefit Results



The range of results for the various P50 cases in Figure 3 show that the Selected Wind Facilities have an attractive profile of benefits that essentially create a "hedge" against future gas price increases and possible carbon regulations. This hedge pays for itself by virtue of the Selected Wind Facilities' benefits that exceed costs even under the lowest projected market fundamentals. In a scenario of low overall customer costs, when wholesale power prices are low (e.g., \$30.79/MWh in 2029 for the low gas w/o CO_2 case), the net customer benefits of the Selected Wind Facilities are lower but still sizable (e.g., just over \$250 million NPV), showing that the facilities more than pay for themselves through avoided fuel and capacity costs. However, in scenarios when overall customer costs are much higher due to higher wholesale power prices (e.g., \$51.39/MWh in 2029 for the high gas with CO_2 case), the net benefits of the Selected Wind Facilities are higher (e.g., nearly \$750 million NPV), thus providing a valuable offset to the higher costs that would otherwise be faced by the Company's customers.

Q. PLEASE EXPLAIN THE IMPACT OF THE CONGESTION MITIGATION OPTION IN TERMS OF CUSTOMER BENEFITS, COSTS, AND RISKS.

A. The three bars on the right in Figure 3 show that in a future of higher congestion costs, the construction of a gen tie can be used to safeguard customer benefits. These gen-tie benefits are based on the "No-SPP-Upgrades" congestion results, which are somewhat higher than the Base Case congestion results as previously shown in Figure 1. Nevertheless, despite the higher congestion costs, customer benefits remain. This means the avoided higher congestion cost would fully pay for the cost of constructing the gen tie under these market conditions. The higher the congestion costs, the more beneficial the gen-tie mitigation option will be.

VII. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows. First, the Company has reasonably relied on the SPP-developed PROMOD Reference Case. With the discussed modifications, it is reasonable to utilize this case for the congestion and loss analyses in both the Company's bid evaluation and customer benefits analysis of the wind facilities proposed and selected in response to the Company's RFP.

Second, there is significant but uncertain congestion in the SPP footprint, specifically affecting the cost of delivering generation from wind plants to load. This makes it important to evaluate the potential future exposure to such congestion cost and how these costs can be mitigated should they unexpectedly exceed the currently estimated levels.

Third, the Company's RFP bid-evaluation process employed in choosing the Selected Wind Facilities was reasonable. In reviewing the bid-evaluation process, I confirmed the reasonableness of the Company's assumptions, analyses, and criteria employed to choose the Selected Wind Facilities, considering the costs of the bids, the locations of the wind farms, exposure to future system congestion and deliverability limitations, and the feasibility of deploying potential congestion risk mitigation options in the event that high levels of congestion materialize in the future. I also found that the choice of Selected Wind Facilities is robust across a broad range of alternative selection criteria.

Fourth, the assumptions, analyses, and approach employed to determine the customer benefits of the Selected Wind Facilities are reasonable. The Company's Customer Benefits Analysis shows that the Selected Wind Facilities offer substantial net benefits under a broad range of market and wind conditions, including at low future energy prices and wind facility production levels. The break-even wholesale power prices are below recent historical price levels, while benefits increase significantly with higher future energy prices. These characteristics make developing the Selected Wind

Facilities a hedge for SWEPCO customers that provides significant benefits under currently projected market conditions and that additionally mitigates the risks and costs associated with future power price increases, higher natural gas prices, possible future carbon regulations, and (through the gen-tie option) increased congestion in the SPP footprint.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

QUALIFICATIONS OF JOHANNES P. PFEIFENBERGER

Johannes Pfeifenberger is a Principal of *The Brattle Group* where he is a member of the firm's Utility Regulation and Electric Power practices. He received a M.A. in Economics and Finance from Brandeis University and holds a M.S. ("*Diplom Ingenieur*") in Electrical Engineering, with a specialization in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria. Prior to joining *The Brattle Group* in 1991, Mr. Pfeifenberger was a consultant with Cambridge Energy Research Associates of Cambridge, Massachusetts, and a research assistant at the Institute of Energy Economics in Vienna, Austria.

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Mr. Pfeifenberger has also presented research findings related to mergers and network access matters to government and antitrust enforcement agencies, including the U.S. Department of Justice, the Merger Task Force of the European Community, the German Cartel Office, the German Ministry of Economics, and the White House National Economic Council.

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PUC DOCKET NO. __________

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

DIRECT TESTIMONY OF

JOEL J. MULTER

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

JULY 15, 2019

TESTIMONY INDEX

SECTION PAGE

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JJM-1	IRS Notices 2017-4, 2016-31, 2015-25, 2014-46, 2013-60, 2013-29 and 84 FR 26508 (June 6, 2019), IRS Notice Credit for Renewable Electricity Production and Refined Coal Production, and Publication of Inflation Adjustment Factor and Reference Prices for Calendar Year 2019
EXHIBIT JJM-2	Summary – Projected PTC Generation and Utilization (AEP Consolidated)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Joel J. Multer. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), as Director Tax Accounting and Regulatory Support. AEP is the parent company of Southwestern Electric Power Company (SWEPCO or the Company). AEPSC supplies accounting, administrative, information systems, engineering, financial, legal, maintenance, and other services to AEP's regulated electric operating companies, including the Company.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a Bachelor of Business Administration Degree in Accounting as well as a Master of Science with a focus on Taxation from the University of Wisconsin-Milwaukee. I am a Certified Public Accountant in the State of Wisconsin.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I joined AEPSC in my current role in December 2018. Prior to that time, I held positions in both public accounting and within the private sector, including over ten years in the regulated utility industry. My previous employers include Ernst & Young, WEC Energy Group, and Walgreens Boots Alliance.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the income tax implications of the three wind generation projects that are the subject of this filing (Selected Wind Facilities), including (1) qualification for the Federal Production Tax Credit (PTC), (2) accelerated tax recovery and qualification for special accelerated depreciation allowances (Bonus Depreciation), and (3) the Company's ability to utilize PTCs generated by the Selected Wind Facilities and the establishment of a Deferred Tax Asset (DTA) for any cash tax deferrals resulting from any limitations.

III. PTC QUALIFICATION REQUIREMENTS

Q. HOW ARE PTCs DETERMINED AND WHAT ARE THE REQUIREMENTS FOR A WIND FACILITY TO QUALIFY?

A. The current rules for determining PTC eligibility and amount are provided for within section 45 of the Internal Revenue Code of 1986,[1] as amended (IRC) and a series of Internal Revenue Service (IRS) notices. The amount of PTC that a taxpayer may claim for any given tax year is equal to a credit rate, adjusted annually for inflation (currently 2.5 cents per kilowatt hour[2] (25 dollars per megawatt hour)), multiplied by the output of electricity produced by the taxpayer:

[1] All IRS documents cited in this testimony are provided in EXHIBIT JJM-1.

[2] 84 FR 26508 (June 6, 2019), IRS Notice Credit for Renewable Electricity Production and Refined Coal Production, and Publication of Inflation Adjustment Factor and Reference Prices for Calendar Year 2019.

- at a wind facility owned by the taxpayer and for which construction began before 2020;
- during the 10-year period following the date the facility is placed in service; and
- sold to unrelated persons.

Section 45 provides for a phaseout of the PTC for wind facilities. In the case of a wind facility, the amount of PTC for any given taxable year shall be reduced by –

- 0% - if construction begins before 2017;
- 20% - if construction begins during 2017;
- 40% - if construction begins during 2018; and
- 60% - if construction begins during 2019.

No PTC is available for a wind facility if the construction begins after 2019.

In Notice 2013-29, the IRS provided two methods that taxpayers may use to establish that construction of a qualified wind facility has begun (the "Begun Construction Requirement"). A taxpayer only needs to satisfy one of the methods to establish that construction of a facility has begun for the purpose of qualifying for the credit. Under the first method, which is a facts and circumstances approach, a taxpayer may satisfy the Begun Construction Requirement by starting physical work of a significant nature ("Physical Work Test") and maintaining a continuous plan of construction. Under the second method, which is a safe harbor, the Begun Construction Requirement of a facility is satisfied upon the taxpayer paying or incurring five percent or more of the total cost of the facility and thereafter making continuous efforts to advance towards completion of the facility (the "Five Percent Safe Harbor"). With the exception of land and property not integral to the facility, all costs properly included in the depreciable basis of the facility are taken into account to determine whether the Five Percent Safe Harbor has been met.

While the requirement to make continuous efforts to advance towards completion of the facility (the "Continuous Efforts Requirement") for purposes of satisfying the Five Percent Safe Harbor is a facts and circumstances test, the IRS in Notice 2013-60 (modified by Notice 2016-31) provided a safe harbor for satisfying the requirement. Under the safe harbor, a facility will be considered to have satisfied the Continuous Efforts Requirement if the facility is placed in service in a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began. For example, if construction began on a facility on January 15, 2016, and the facility is placed in service by December 31, 2020, the facility will be considered to satisfy the Continuous Efforts Requirement safe harbor.

Notices 2013-60 and 2014-46 also provide that if a facility consisting of more than tangible personal property is sold to an unrelated person after the Begun Construction Requirement is satisfied, the taxpayer who acquires the facility may take into account the work performed or amount paid by the unrelated transferor for purposes of determining whether the facility satisfies the Physical Work Test or the Five Percent Safe Harbor. Thus, there is no requirement that a taxpayer own the facility at the time construction began in order to be able to claim PTCs with respect to the facility.

A summary of the qualified wind facility PTC qualification requirements is as follows–

Date Construction Begins*	Continuous Efforts Requirement Placed-in-Service Safe Harbor**	PTC %
Before 12/31/2016	Before 12/31/2020	100%
During 2017	Before 12/31/2021	80%
During 2018	Before 12/31/2022	60%
During 2019	Before 12/31/2023	40%
After 12/31/2019	N/A	0%

* Satisfaction of the Begun Construction Requirement by a developer is transferrable to a buyer

** Taxpayer may satisfy Continuous Construction by either (1) meeting the placed-in-service safe harbor or (2) via facts and circumstances

Q. DO THE SELECTED WIND FACILITIES QUALIFY FOR PTCs AND AT WHAT PERCENTAGE?

A. It is expected that the Selected Wind Facilities will be eligible for PTCs at either a 100 percent or 80 percent level. Projects solicited for consideration under the Company's Request for Proposal were required to have the ability to meet at least the 80 percent PTC threshold as a result of having satisfied the Begun Construction Requirement no later than December 31, 2017, and having an anticipated placed-in-service date no later than December 31, 2021. The Selected Wind Facilities are expected to have satisfied the Begun Construction Requirement in either 2016 or 2017 by satisfying the Five Percent Safe Harbor through purchases of equipment, including wind turbine generators and cable, which will be incorporated into the projects. As discussed by Company witness Godfrey, under the terms of the Purchase and Sale Agreement for each Selected Wind Facility, the Company may terminate the agreement, and will have no obligation to purchase the project, if the project does not reach substantial completion by the Substantial Completion Deadline (December 15, 2020, for any project that satisfied the Begun Construction Requirement in 2016 and December 15, 2021, for any project that satisfied the Begun Construction Requirement in 2017), which is a date prior to the placed-in-service safe-harbor deadline for satisfying the Continuous Efforts Requirement for the relevant project. Therefore, each of the Selected Wind Facilities will satisfy the Continuous Efforts Requirement safe harbor by being placed in service in a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began.

IV. ACCELERATED TAX DEPRECIATION AND BONUS DEPRECIATION ELIGIBILITY

Q. WILL THE ASSETS COMPRISING THE SELECTED WIND FACILITIES QUALIFY FOR BONUS DEPRECIATION?

A. No. Under IRC section 168(k), a taxpayer that owns qualified property is generally allowed additional depreciation (bonus depreciation) in the year such property is placed into service (with corresponding reductions in basis; therefore, reducing regular tax accelerated depreciation deductions otherwise allowed).

Prior to enactment of the Tax Cuts and Jobs Act in 2017, there was no rule that excluded property from qualifying for bonus depreciation based on the property's use. The Tax Cuts and Jobs Act amended section 168(k) to exclude from the definition of qualifying property any property that is public utility property, which includes property used in the trade or business of the furnishing or sale of electrical energy if the rates for furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof, by any agency or instrumentality of the United States, by a public service or public utility commission or other similar body of any State or political subdivision thereof. As a result, because the proposed assets of the Selected Wind Facilities would be public utility property acquired after September 27, 2017, they will not be eligible for bonus depreciation.

Q. WHAT IS THE TAX RECOVERY LIFE FOR THE ASSETS COMPRISING THE SELECTED WIND FACILITIES?

A. The Modified Accelerated Cost-Recovery System (MACRS) establishes the class lives over which property is depreciated under the IRC. The assets underlying the Selected Wind Facilities will primarily be comprised of property that is classified as five-year property under MACRS (IRC Sec. 168(a)(3)(B)(vi) with reference to Sec. 48(a)(3)(A)).

V. CREDIT LIMITATIONS AND DEFERRAL OF CASH TAX BENEFITS

Q. ARE THERE LIMITATIONS ON A TAXPAYER'S ABILITY TO USE PTCs TO OFFSET ITS ANNUAL INCOME TAX LIABILITY?

A. Yes. IRC section 38(c) generally limits a taxpayer's use of General Business Credits (of which PTCs are a component) to 75 percent of the taxpayer's regular tax liability before applying any credits. Any General Business Credits unable to be utilized in offsetting regular tax in a given year may be carried forward and used to reduce regular tax liabilities in the succeeding 20 years. For taxpayers, including AEP, that file income tax returns as a consolidated group, the limitation on the ability to utilize credits is determined at the consolidated group level.

Q. HOW ARE CREDIT LIMITATIONS DETERMINED AT THE CONSOLIDATED GROUP LEVEL APPLIED TO THE CREDITS GENERATED BY THE MEMBERS OF THE CONSOLIDATED GROUP?

A. In accordance with IRC sections 1501, 1502, and the Treasury Regulations thereunder, the utilization of consolidated General Business Credits shall be equitably allocated to those members of the consolidated group whose investments or contributions generated the tax credits.

Q. HOW ARE TAX CREDIT CARRY FORWARDS ACCOUNTED FOR AND WHAT ARE THE IMPLICATIONS OF THE ASSOCIATED CASH TAX DEFERRAL?

A. As previously noted, General Business Credits that cannot be utilized in a given tax year due to section 38(c) limitations may be carried forward and used, subject to limitation, to offset regular tax liability in the succeeding 20 years. Any credits not utilized after the 20-year carry forward period expire.

General Business Credits subject to limitation are recognized as a DTA during the 20-year carryforward period to the extent the taxpayer anticipates the ability to utilize the credits to reduce its future tax liabilities prior to expiration. Please refer to the testimony of Company witness Aaron for ratemaking implications of a DTA resulting from such cash tax deferral.

Q. WILL AEP HAVE THE ABILITY TO UTILIZE ALL PTCs GENERATED BY THE SELECTED WIND FACILITIES IN THE YEAR OF GENERATION?

A. No. Within its consolidated tax return for AEP and subsidiaries, AEP anticipates generating PTCs in excess of the section 38(c) limitation for each year of the 10-year credit generation period. The PTCs from the Selected Wind Facilities will provide an up-front benefit to customers in the year of generation, however, as a result of the section 38(c) limitation, the cash tax benefit associated with PTCs carried forward to subsequent years will be reflected as a DTA within the Company's financial statements.

Q. HAS AEP PROJECTED THE PTC LIMITATION AND CORRESPONDING DTA OVER THE DURATION OF THE PTC UTILIZATION PERIOD?

A. Yes. AEP has prepared projections of the generation and utilization of tax credits, including PTCs produced from the Selected Wind Facilities, based upon AEP and its subsidiaries' forecasted consolidated tax liabilities. The projections have been determined considering the Selected Wind Facilities at both the 50% probability (P50) and 95% probability (P95) production levels. The results reflect annual limitation of the PTCs generated by the Selected Wind Facilities with deferral of the cash tax benefits for periods of up to four years and peak cash tax deferral amounts of approximately $300 million and $232 million under P50 and P95 production levels, respectively. Please reference EXHIBIT JJM-2 for a summary of the Company's projected PTC generation from its ownership share of the Selected Wind Facilities, the utilization of such PTCs and the cumulative cash tax deferral resulting from limitations under the IRC as determined based on AEP and its subsidiaries' consolidated tax liabilities.

Q. WHAT ASSUMPTIONS WERE USED IN AEP'S PROJECTIONS OF TAXABLE INCOME AND TAX CREDIT UTILIZATION?

A. Projections were based upon the AEP 2018 Control Budget developed in conjunction with Edison Electrical Institute's November 2018 financial conference which is the Company's most recently compiled enterprise wide forecast, with modifications to reflect additional known and expected projects.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Beginning of Construction for Sections 45 and 48

Notice 2017-04

SECTION 1. PURPOSE

Section 38 of the Internal Revenue Code (the Code) allows certain business credits against the tax imposed by Chapter 1 of the Code. Among the credits allowed by § 38 is the credit for renewable electricity production described in § 45(a). To qualify for the renewable electricity production tax credit, electricity must, among other things, be produced by the taxpayer at a qualified facility as defined in § 45(d). If the taxpayer makes an election under § 48(a)(5), the taxpayer may instead claim the investment tax credit with respect to the facility.

On December 18, 2015, the Protecting American from Tax Hikes Act of 2015, Pub. L. No. 114-113, Div. Q, 129 Stat. 2242 (the PATH Act), enacted amendments to the production tax credit under § 45 (PTC) and the investment tax credit under § 48 (ITC) for certain renewable energy facilities. The PATH Act extended the PTC for two years with respect to certain facilities the construction of which begins before January 1, 2017, and further extended the PTC for wind facilities the construction of which begins before January 1, 2020. The PATH Act also modified the PTC for wind facilities by providing that the credit will phase out over the next four years. Under § 45(b)(5) as modified by the PATH Act, wind facilities the construction of which begins before January 1, 2017 are eligible to receive 100 percent of the PTC; wind facilities the construction of which begins after December 31, 2016 and before January 1, 2018 are eligible to receive 80 percent of the PTC; wind facilities the construction of which begins after December 31, 2017 and before January 1, 2019 are eligible to receive 60 percent of the PTC; and wind facilities the construction of which begins after December 31, 2018 and before January 1, 2020 are eligible to receive 40 percent of the PTC. In addition, the PATH Act extended the election to claim the ITC in lieu of the PTC with respect to certain renewable energy facilities if construction of such facility begins before January 1, 2017 (or January 1, 2020 in the case of wind facilities).

Similarly, the PATH Act also extended and modified the ITC for solar energy facilities the construction of which begins before January 1, 2022. The Treasury Department and the Internal Revenue Service (Service) anticipate issuing separate guidance addressing the extension and modification of the ITC for solar energy facilities.

This notice updates and clarifies the guidance provided in Notice 2013-29, 2013-1 C.B. 1085; Notice 2013-60, 2013-2 C.B. 431; Notice 2014-46, 2014-2 C.B. 520; Notice 2015-25, 2015-13 I.R.B. 814; and Notice 2016-31, 2016-23 I.R.B. 1025 (collectively "the prior IRS notices"). The Service will not issue private letter rulings to taxpayers regarding the application of this notice, the prior IRS notices, or the beginning of construction requirement under §§ 45(d) and 48(a)(5).

SECTION 2. BACKGROUND

On June 6, 2016, the Treasury Department and the Service published Notice 2016-31 to extend and modify the Continuity Safe Harbor, as defined in section 3.02 of Notice 2013-60, and to provide additional guidance regarding the beginning of construction requirement. Notice 2016-31 also clarifies the application of the Five Percent Safe Harbor, as defined in section 5 of Notice 2013-29, to retrofitted renewable energy facilities.

After the publication of Notice 2016-31, the Treasury Department and the Service received requests for further clarification regarding the extension and modification of the Continuity Safe Harbor, the prohibition against combining methods by which to satisfy the beginning of construction requirement, and the costs that may be included in the Five Percent Safe Harbor for retrofitted renewable energy facilities. This notice modifies and clarifies Notice 2016-31. Except as otherwise specified in this notice, the guidance provided in the prior IRS notices continues to apply.

SECTION 3. EXTENSION AND MODIFICATION OF THE CONTINUITY SAFE HARBOR

Section 3.02 of Notice 2013-60 provides a Continuity Safe Harbor that allows a facility to be deemed to satisfy the Continuous Construction Test, as defined in section 4.06 of Notice 2013-29 (for purposes of satisfying the Physical Work Test provided in section 4 of Notice 2013-29), or the Continuous Efforts Test, as defined in section 5.02 of Notice 2013-29 (for purposes of satisfying the Five Percent Safe Harbor), based on the date on which a facility is placed in service. If a facility does not satisfy the Continuity Safe Harbor, whether the facility satisfies the Continuous Construction or Continuous Efforts Tests is determined by the relevant facts and circumstances.

Section 3 of Notice 2016-31 modifies and extends the Continuity Safe Harbor by providing that if a taxpayer places a facility in service by the later of (1) a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began or (2) December 31, 2016, the facility will be considered to satisfy the Continuity Safe Harbor.

This notice modifies the Continuity Safe Harbor provided in section 3 of Notice 2016-31 by providing that if a taxpayer places a facility in service by the later of (1) a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began or (2) December 31, 2018, the facility will be considered to satisfy the Continuity Safe Harbor. For example, if construction begins on a facility on January 15, 2013, and the facility is placed in service by December 31, 2018, the facility will be considered to satisfy the Continuity Safe Harbor. Alternatively, if construction begins on a facility on January 15, 2016, and the facility is placed in service by December 31, 2020, the facility will be considered to satisfy the Continuity Safe Harbor.

SECTION 4. PROHIBITION AGAINST COMBINING METHODS BY WHICH TO SATISFY THE BEGINNING OF CONSTRUCTION REQUIREMENT

Section 4.01 of Notice 2016-31 provides that a taxpayer may not rely upon the Physical Work Test and the Five Percent Safe Harbor in alternating calendar years to satisfy the beginning of construction requirement or the Continuity Requirement. For example, if a taxpayer performs physical work of a significant nature on a facility in 2015, and then pays or incurs five percent or more of the total cost of the facility in 2016, the Continuity Safe Harbor will be applied beginning in 2015, not in 2016.

This notice modifies section 4.01 of Notice 2016-31 by providing that this rule applies to facilities the construction of which begins after June 6, 2016 (the date on which Notice 2016-31 was published in I.R.B. 2016-23).

SECTION 5. COSTS INCLUDED IN THE APPLICATION OF FIVE PERCENT SAFE HARBOR TO RETROFITTED FACILITIES

Section 6.01 of Notice 2016-31 provides that a facility may qualify as originally placed in service even though it contains some used property, provided the fair market value of the used property is not more than 20 percent of the facility's total value (the cost of the new property plus the value of the used property) (the 80/20 Rule).

Section 6.02 of Notice 2016-31 provides that to satisfy the beginning of construction requirement for §§ 45 and 48, the Five Percent Safe Harbor is applied only with respect to the cost of new property used to retrofit an existing facility. Therefore, only expenditures paid or incurred that relate to new construction should be taken into account for purposes of the Five Percent Safe Harbor.

Section 5.01(1) of Notice 2013-29 provides that for purposes of the Five Percent Safe Harbor, all costs properly included in the depreciable basis of the facility are taken into account to determine whether the Safe Harbor has been met. The total cost of the facility does not include the cost of land or any property not integral to the facility, as described in section 4.05(1) of Notice 2013-29.

This notice clarifies that for purposes of the 80/20 rule, the cost of new property includes all costs properly included in the depreciable basis of the new property.

SECTION 6. EFFECT ON OTHER DOCUMENTS

Notice 2013-29, Notice 2013-60, Notice 2014-46, Notice 2015-25, and Notice 2016-31 are clarified and modified. The guidance provided in this notice is applicable to any project for which a taxpayer claims the PTC or the ITC under §§ 45 or 48, as modified by ATRA, that is placed in service after January 2, 2013.

SECTION 7. DRAFTING INFORMATION

The principal author of this notice is Jennifer C. Bernardini of the Office of Associate Chief Counsel (Passthroughs & Special Industries). For further information regarding this notice contact Ms. Bernardini on (202) 317-6853 (not a toll-free call).

Beginning of Construction for Sections 45 and 48

Notice 2016-31

SECTION 1. PURPOSE

Section 38 of the Internal Revenue Code (the Code) allows certain business credits against the tax imposed by Chapter 1 of the Code. Among the credits allowed by § 38 is the credit for renewable electricity production described in § 45(a). To qualify for the renewable electricity production tax credit, electricity must, among other things, be produced by the taxpayer at a qualified facility. Section 45(a)(2)(A). Section 45(d) defines qualified facilities for purposes of § 45.

Prior to the American Taxpayer Relief Act of 2012, Pub. L. No. 112-240, 126 Stat. 2313 (ATRA), § 45(d) required a facility to be placed in service before January 1, 2014, in order to be a qualified facility, except for qualified wind facilities which had to be placed in service before January 1, 2013. ATRA modified the definition of certain qualified facilities under § 45(d) by replacing the placed in service requirement with a beginning of construction requirement. ATRA provided that a taxpayer is eligible to receive the renewable electricity production tax credit (PTC) under § 45, or the energy investment tax credit (ITC) under § 48 in lieu of the PTC, with respect to certain renewable energy facilities if construction of such facility began before January 1, 2014. On December 19, 2014, the Tax Increase Prevention Act of 2014, Pub. L. No. 113-295, 128 Stat. 4021 (TIPA), extended by one year, to January 1, 2015, the date by which construction of a qualified facility must begin.

On December 18, 2015, the Protecting American from Tax Hikes Act of 2015, Pub. L. No. 114-113, Div. Q, 129 Stat. 2242 (the PATH Act), enacted amendments to the PTC and the ITC for certain renewable energy facilities. The PATH Act extended the PTC for two years with respect to certain facilities the construction of which begins before January 1, 2017, and further extended the PTC for wind facilities the construction of which begins before January 1, 2020. The PATH Act also modified the PTC for wind facilities by providing that the credit will phase out over the next four years.[1] The PATH Act also extended the ITC for solar energy facilities the construction of which begins before January 1, 2022. The Treasury Department and the Internal Revenue Service (Service) anticipate issuing separate guidance addressing the extension of the ITC for solar energy facilities.

The Service will not issue private letter rulings to taxpayers regarding the application of this notice or the application of the beginning of construction requirement under §§ 45(d) and 48(a)(5) as provided in Notice 2013-29, 2013-1 C.B. 1085; Notice 2013-60, 2013-2 C.B. 431; Notice 2014-46, 2014-2 C.B. 520; and Notice 2015-25, 2015-13 I.R.B. 814 (collectively "the prior IRS notices").

SECTION 2. BACKGROUND

[1] As a result, facilities the construction of which begins before January 1, 2017, are eligible to receive 100% of the PTC; facilities the construction of which begins after December 31, 2016, and before January 1, 2018, are eligible to receive 80% of the PTC; facilities the construction of which begins after December 31, 2017, and before January 1, 2019, are eligible to receive 60% of the PTC; and facilities the construction of which begins after December 31, 2018, and before January 1, 2020, are eligible to receive 40% of the PTC.

On May 13, 2013, the Treasury Department and the Service published Notice 2013-29, which provides two methods that a taxpayer may use to establish that construction of a qualified facility has begun. A taxpayer may establish the beginning of construction by beginning physical work of a significant nature as described in section 4 of Notice 2013-29 (Physical Work Test). Alternatively, a taxpayer may establish the beginning of construction by meeting the safe harbor provided in section 5 of Notice 2013-29 (Five Percent Safe Harbor). Both methods require that a taxpayer make continuous progress towards completion once construction has begun, as set forth in section 4.06 of Notice 2013-29 (Continuous Construction Test) for taxpayers using the Physical Work Test and section 5.02 of Notice 2013-29 (Continuous Efforts Test) for taxpayers using the Five Percent Safe Harbor (collectively, the Continuity Requirement).

On October 28, 2013, the Treasury Department and the Service published Notice 2013-60, which provides a safe harbor for satisfying the Continuity Requirement (the Continuity Safe Harbor). Under the Continuity Safe Harbor in section 3.02 of Notice 2013-60, if a facility was placed in service before January 1, 2016, the facility will be considered to satisfy the Continuity Requirement. Failure to satisfy the Continuity Safe Harbor does not mean that a facility has not satisfied the Continuity Requirement, however. If a facility was not placed in service before January 1, 2016, whether the facility satisfies the Continuity Requirement will be determined by the relevant facts and circumstances, as described in sections 4.06 and 5.02 of Notice 2013-29.

After the publication of Notice 2013-60, the Treasury Department and the Service